COMMONWEALTH OF VIRGINIA
Department of Environmental Quality
Valley Regional Office

STATEMENT OF LEGAL AND FACTUAL BASIS

Valley Proteins, Inc.
151 Val-Pro Road
P.O. Box 3588
Winchester Virginia
Permit No. VRO80144

Title V of the 1990 Clean Air Act Amendments required each state to develop a permit program to ensure that certain facilities have federal Air Pollution Operating Permits, called Title V Operating Permits. As required by 40 CFR Part 70 and 9 VAC 5 Chapter 80, Valley Proteins, Inc. has applied for a renewal of the Title V Operating Permit for its Linville facility. The Department has reviewed the application and has prepared a Title V Operating Permit.

Engineer/Permit Contact: Anita Riggleman Date: 12/29/09
Anita Riggleman
(540) 574-7852

Air Permit Manager: Janardan R Pandey Date: 12/29/09
Janardan R. Pandey, P.E.

Deputy Regional Director: [signature] Date: 12/30/09
B. Keith Fowler

FACILITY INFORMATION

Permittee
Valley Proteins, Inc.
151 Val-Pro Road
P.O. Box 3588
Winchester, Virginia 22604

Responsible Official
Hobie Halterman
General Manager

Facility
Valley Proteins, Inc. – Linville
6230 Kratzer Road
Linville, VA 22834

Contact Person
Robert T. Vogler
Director of Environmental Affairs
(540) 877-2590

Plant Identification Number: 51-165-0023

Facility Description: SIC Code 2077 – Rendering of animal by-products and fats
NAISC 311613 – Rendering & Meat Byproduct Processing

Valley Proteins, Inc. (VP) renders inedible animal by-products and surplus restaurant fats to produce protein solids and fats which are sold to feed mills. One 22.5 ton/hr and one 18.1 ton/hr continuous cookers, five 1.75 ton/hr feather cookers, and two 3.50 ton/hr eggshell cookers breakdown and dehydrate raw animal materials into solids and fats using steam from five residual oil, finished animal/vegetable oil, and natural gas-fired boilers. One additional boiler (B-5) which is distillate oil-fired is located at the facility but does not provide steam or heat to the rendering facility. The processed animal/vegetable oil may be mixed with distillate oil and may be used as a fuel for the boilers, depending on market and availability. One 10.0 ton/hr feather dryer is also used in the operation. Particulate matter, volatile organic compound, and odor emissions are controlled by a Venturi scrubber, a packed tower scrubber, and five boilers. Fats and solids are stored in fat tanks and feed bins, respectively.

The facility is a PSD and Title V major source of SO_2. This source is located in an attainment area for all pollutants. The facility was previously permitted under minor NSR permits issued on October 23, 1992 and July 1, 2005, as amended December 11, 2006 and May 23, 2008.

CHANGES TO EXISTING TITLE V PERMIT

Changes from the previous Title V permit are:

- Update name of Contact Person
- Update of references to current NSR permit dated July 1, 2005, as amended December 11, 2006 and May 23, 2008
- Incorporate conditions from the minor NSR permit dated July 1, 2005, as amended December 11, 2006 and May 23, 2008 for the replacement continuous cooker (CC-2R), the new boiler (B-6), reactivation of boiler (B-4), a new Venturi scrubber (VS2), a new packed tower scrubber (PTS-1), and the blending of distillate oil with animal fat
- Remove emission factors to be consistent with current minor NSR permit
- Add a 2,000 gallon storage tank for gasoline to the Insignificant Emission Units table
- Remove table of emission tests methods to maintain consistency with current permitting practices
- Update General Conditions with current boilerplate language

These changes are discussed in more detail below.

COMPLIANCE STATUS

A full compliance evaluation of this facility, including a site visit, was conducted on May 21, 2009. In addition, all reports and other data required by permit conditions or regulations, which are submitted to DEQ, are evaluated for compliance. Based on these compliance evaluations, the facility has not been found to be in violation of any state or federal applicable requirements at this time.

EMISSION UNIT AND CONTROL DEVICE IDENTIFICATION

The emissions units at this facility consist of the following:

Table I. Significant Emission Units

Emission Unit ID	Stack ID	Emission Unit Description	Size/Rated Capacity*	Pollution Control Device Description (PCD)	PCD ID	Pollutants Controlled	Applicable Permit Date
Fuel Burning Equipment							
B-1	B1E-1	Cleaver Brooks CB400-700 boiler, manufactured in 1974	29.291 MMBtu/hr maximum heat input	---	---	---	7/1/05 as amended 12/11/06 and 5/23/08
B-2	B2E-1	Cleaver Brooks CB400-700 boiler, manufactured in 1974	29.291 MMBtu/hr maximum heat input	---	---	---	7/1/05 as amended 12/11/06 and 5/23/08
B-3	B3E-1	Cleaver Brooks CB400-700 boiler, manufactured in 1974	29.291 MMBtu/hr maximum heat input	---	---	---	7/1/05 as amended 12/11/06 and 5/23/08
B-4	B4E-1	Superior 4-S-3004 stand-by boiler, manufactured in 1973	25 MMBtu/hr maximum heat input	---	---	---	7/1/05 as amended 12/11/06 and 5/23/08
B-6	B6E-1	Johnston Series 509 boiler, manufactured in 1994	48.4 MMBtu/hr maximum heat input	---	---	---	7/1/05 as amended 12/11/06 and 5/23/08
Rendering Process Equipment							
CC-1	B1E-1 B2E-1 B3E-1 B4E-1 B6E-1 PTSE-1	Dupps 320U continuous cooker equipped with an air-cooled condenser, manufactured in 1988 ** OR Dupps 320U continuous cooker equipped with a shell & tube condenser, manufactured in 1988	22.5 tons/hr maximum solids input	Venturi scrubber and Cleaver Brooks boilers with firebox manufactured by AC Corporation or packed tower scrubber (when boilers are operating at firing load < 20%)	VS1 B-1 B-2 B-3 B-4 B-6 PTS-1	PM PM-10 VOC	7/1/05 as amended 12/11/06 and 5/23/08

Emission Unit ID	Stack ID	Emission Unit Description	Size/Rated Capacity*	Pollution Control Device Description (PCD)	PCD ID	Pollutants Controlled	Applicable Permit Date
CC-2R	B1E-1 B2E-1 B3E-1 B4E-1 B6E-1 PTSE-1	Dupps 260J continuous cooker equipped with a shell and tube condenser, manufactured in 2005	18.1 tons/hr maximum solids input	Venturi scrubber and Cleaver Brooks boilers with firebox manufactured by AC Corporation or packed tower scrubber (when boilers are operating at firing load < 20%)	VS1 B-1 B-2 B-3 B-4 B-6 PTS-1	PM PM-10 VOC	7/1/05 as amended 12/11/06 and 5/23/08
FC1-5	B1E-1 B2E-1 B3E-1 B4E-1 B6E-1 PTSE-1	Dupps 5x12 feather cookers equipped with an entrainment tank and an air-cooled condenser, manufactured in 1972-1976	1.75 tons/hr maximum solids input each	Venturi scrubber and Cleaver Brooks boilers with firebox manufactured by AC Corporation or packed tower scrubber (when boilers are operating at firing load < 20%)	VS1 B-1 B-2 B-3 B-4 B-6 PTS-1	PM PM-10 VOC	7/1/05 as amended 12/11/06 and 5/23/08
EC-1,2	B1E-1 B2E-1 B3E-1 B4E-1 B6E-1 PTSE-1	Dupps 5x16 eggshell cookers equipped with an entrainment tank and an air-cooled condenser, manufactured in 1974	3.5 tons/hr maximum solids input each	Venturi scrubber and Cleaver Brooks boilers with firebox manufactured by AC Corporation or packed tower scrubber (when boilers are operating at firing load < 20%)	VS1 B-1 B-2 B-3 B-4 B-6 PTS-1	PM PM-10 VOC	7/1/05 as amended 12/11/06 and 5/23/08
FD-1	B1E-1 B2E-1 B3E-1 B4E-1 B6E-1 PTSE-1	Davenport feather dryer equipped with an entrainment tank and Cooling Products Inc. A-frame air-cooled condenser, Model # 111-6000, manufactured in 1992	10.0 tons/hr maximum combined solids input (5.4 tons/hr feather meal product output at 10% moisture)	Venturi scrubber and Cleaver Brooks boilers with firebox manufactured by AC Corporation or packed tower scrubber (when boilers are operating at firing load < 20%)	VS1 B-1 B-2 B-3 B-4 B-6 PTS-1	PM PM-10 VOC	10/23/92
---	PTSE-1	Cooker process equipment	---	Venturi scrubber and packed tower scrubber	VS2 PTS-1	PM PM-10 VOC	7/1/05 as amended 12/11/06 and 5/23/08

*The Size/Rated capacity is provided for informational purposes only, and is not an applicable requirement.
** This scenario is only used when water is not available to operate the shell & tube condenser.

EMISSIONS INVENTORY

A copy of the 2008 CEDS emission inventory is included as Attachment A. Emissions are summarized in the following tables.

Table II. 2008 Actual Criteria Pollutant Emissions for the Rendering Facility

	Criteria Pollutant Emissions (tons/yr)				
	VOC	CO	SO_2	PM-10	NO_x
Boilers B-1 – B-6*	0.75	8.84	129.14	10.00	48.32
Rendering Equipment	6.79	--	--	3.80	--
Total	**7.54**	**8.84**	**129.14**	**13.80**	**48.32**

* Emissions from Boiler B-5 are included above although Boiler B-5 does not supply steam or heat to the Valley Proteins, Inc. – Linville rendering facility.

Insignificant amounts of hazardous air pollutants are emitted from fuel burning and have not been included in the inventory.

EMISSION UNIT APPLICABLE REQUIREMENTS - Fuel Burning Equipment (B-1 through B-6)

Limitations

The Johnston boiler (B-6) is subject to NSPS, Subpart Dc. The following limitations are state BACT, NSPS, and other applicable requirements from the minor NSR permit issued on July 1, 2005, as amended December 11, 2006 and May 23, 2008. Please note that the condition numbers are from that permit; a copy of the permit is included as Attachment B.

Condition 2: The operating restriction for boiler (B-5) to not supply steam or heat to the rendering facility.

Condition 3: The operating restriction for only the Johnston boiler (B-6) to provide steam for the Dupps 260J cooker (CC-2R). The Superior boiler (B-4) may provide steam to the cooker when the Johnston boiler (B-6) is not operating.

Condition 4: The operating restriction for boiler Superior (B-4) to provide steam as a back up to any one of the three Cleaver-Brooks boilers (B-1, B-2, and B-3).

Condition 5: The approved fuels for the boilers (B-1, B-2, B-3, B-4, and B-6) are residual oil, natural gas, and processed animal fat.

Condition 6: The processed animal fat may be blended with distillate oil in the ratio of a maximum of 10 gallons of distillate oil to 6500 gallons of processed animal fat.

Condition 7: Processed animal fat fuel throughput limit for the three Cleaver-Brooks boilers (B-1, B-2, and B-3).

Condition 8: Residual oil and natural gas fuel throughput limits for the Johnston and Superior boilers (B-4 and B-6).

Condition 9: Substitution ratio for processed animal fat as a fuel for the Superior boiler (B-4) or the Johnston boiler (B-6).

Condition 10: Fuel specification requirement for residual oil.

Condition 11: Fuel specification requirements for distillate oil and processed animal fat.

Condition 14: Requires proper operation and maintenance of the combustion equipment.

Condition 15: Hourly emissions limits for the three Cleaver-Brooks boilers (B-1, B-2 and B-3) when burning processed animal fat.

Condition 16: Hourly emissions limits for the Johnston boiler (B-6) for all fuels. The particulate emission limits do not include condensibles.

Condition 17: Hourly emissions limits for the Superior boiler (B-4) for all fuels. The particulate emission limits do not include condensibles.

Condition 18: Combined annual emissions limits for the Cleaver-Brooks boilers (B-1, B-2 and B-3) when burning processed animal fat.

Condition 19: Combined annual emissions limits for the Superior and Johnston boilers (B-4 and B-6) for all fuels. The particulate emission limits do not include condensibles.

Condition 20: Visible emission limit for the Cleaver-Brooks boilers (B-1, B-2 and B-3) when burning processed animal fat.

Condition 21: Visible emission limit for the Cleaver-Brooks boilers (B-1, B-2 and B-3) when burning residual oil or natural gas.

Condition 22: Visible emission limit for the Superior and Johnston boilers (B-4 and B-6) when burning processed animal fat or natural gas.

Condition 23: Visible emission limit for the Johnston boiler (B-6) when burning residual oil.

Condition 24: Visible emission limit for the Superior boiler (B-4) when burning residual oil.

Condition 25: Requirements by reference for NSPS, 40 CFR Subpart Dc, for the Johnston boiler (B-6).

The following Virginia Administrative Codes that have specific emission requirements have been determined to be applicable:

9 VAC 5-40-900 - Particulate matter emission limit for fuel burning equipment installations as determined by the equation $E = 1.0906H^{-0.2594}$, where E is the emission limit in lbs/MMBTU and H is the total capacity in MMBTU/hr of the three Cleaver Brooks boilers (B-1, B-2, and B-3). The limit is 0.34 lb/MMBTU based on the combined rated heat input of 87.873 MMBTU/hr for the three boilers (B-1, B-2, and B-3).

9 VAC 5-40-930 - Sulfur dioxide emission limit for fuel burning equipment installations as determined by the equation S = 2.64K, where S is the emission limit in lbs/hr and K is the total heat input capacity in MMBTU/hr of the three Cleaver Brooks boilers (B-1, B-2, and B-3). The limit is 232.0 lb/hr based on the combined rated heat input of 87.873 MMBTU/hr for the three boilers (B-1, B-2, and B-3).

The following additional requirement has been included to demonstrate compliance with the sulfur dioxide and visible emission limits:

9 VAC 5-80-110 - The maximum sulfur content of the residual oil burned in the Cleaver Brooks boilers (B-1, B-2, and B-3) shall not exceed 2.5 % by weight per shipment.

Periodic Monitoring and Recordkeeping

The Johnston boiler (B-6) is subject to NSPS, Subpart Dc. This permit includes requirements for monitoring and recordkeeping to satisfy Part 70 requirements. The monitoring and recordkeeping requirements in Conditions 12, 13, 14, 26, 27, and 39 of the NSR permit dated July 1, 2005, as amended December 11, 2006 and May 23, 2008, have been modified to meet Part 70 requirements. The NSPS requirements for boiler (B-6) have been incorporated into the operating permit including the continuous opacity monitor (COMS) requirements when the boiler is burning residual oil.

In addition to the monitoring requirements from the NSR permit, opacity has been chosen as a surrogate indicator for particulate matter emissions. The permittee will perform weekly inspections of the boiler stacks to determine the presence of visible emissions. If during the inspection, visible emissions are observed, the permittee has the option of either taking timely corrective action so that the stack operates with no visible emissions (the permittee must initiate corrective action within 4 hours and return to no visible emissions within 24 hours of the inspection) or conducting an EPA Method 9 (40 CFR Part 60, Appendix A) visible emission evaluation (VEE). The VEE will be conducted for a minimum of six minutes. If any of the observations exceed the applicable opacity limit, the observation period will continue for a total of 60 minutes of observation or until a violation of the opacity standard is recorded.

If the results of the VEE exceed the opacity standard, the permittee is required to do a particulate matter performance test within 90 days of the exceedance. No more than one test per year per boiler is required as long as the performance test results do not exceed the particulate matter emission limit. A concurrent VEE is required with the performance test.

When burning fuels other than processed animal fat, the particulate matter emission limit of 0.34 pound per million Btu input applies to the combined capacity of the three Cleaver Brooks boilers (87.873 MMBtu/hr). This is equal to 29.88 lb/hr. Potential particulate emissions from the operation of the three Cleaver Brooks (B-1 to B-3) combined using AP-42 emission factors are shown in the following table.

Table III. Particulate Emissions

Fuel Type	Capacity of Fuel Burning Equipment	Maximum Hourly Throughput	AP-42 Emission Factor for PM (lb/1000 gal)	Maximum Sulfur Content (S)	Maximum Emissions of PM (lb/hr)	Calculated PM Emission Standard (lb/hr)
Residual Oil	87.873 MMBtu/hr	0.586 mgal/hr	9.19 S + 3.22	2.5	15.35	29.88

The maximum expected particulate emissions using the EPA AP-42 emissions factor is approximately half of the allowable limit. Therefore, there is reasonable assurance that the particulate matter emission limit will not be violated as long as the fuel sulfur content and the opacity limit are not exceeded. Boiler inspection reports have revealed no past violations of the opacity limitations contained in this permit.

When burning fuels other than processed animal fat, the allowable sulfur dioxide emission limit for the three Cleaver Brooks boilers combined equals 232.0 lbs/hr. The AP-42 emission factor for sulfur dioxide assumes that all of the sulfur is converted to sulfur dioxide. The maximum sulfur dioxide emissions from the boilers are included in the following table.

Table IV. Sulfur Dioxide Emissions

Fuel Type	Capacity of Fuel Burning Equipment	Maximum Hourly Throughput	AP-42 Emission Factor for Sulfur Dioxide (lb/1000 gal)	Maximum Sulfur Content (S)	Maximum Emissions of Sulfur Dioxide (lb/hr)	Sulfur Dioxide Emission Standard (lb/hr)
Residual Oil	87.873 MMBtu/hr	0.586 mgal/hr	157 S	2.5	229.93	232.0

Since the AP-42 emission factor assumes that all of the sulfur in the fuel is converted to sulfur dioxide when burning residual oil, the sulfur dioxide emission limit cannot be exceeded as long as the sulfur content of the fuel does not exceed 2.5 % for residual oil. The permittee is required to obtain a certification from the fuel supplier with each shipment of residual oil. The certification must include the name of the fuel supplier, the date the oil was received, the quantity of oil delivered in the shipment, and the sulfur content (in percent) of the residual oil. The permittee is required to retain the fuel certifications.

Actual particulate matter and sulfur dioxide emissions from the operation of the three boilers (B-1, B-2, and B-3) when burning residual will be calculated using the following equations:

For residual oil combustion:

$$E = F \times O \qquad \text{Equation 1}$$

Where:

E	=	Emission Rate (lb/time period)
F	=	Pollutant specific emission factors as follows:

PM = $9.19\ S + 3.22$ lb/1000 gal (S = weight percent sulfur)
SO_2 = 157 S lb/1000 gal (S = weight percent sulfur)

O = residual oil consumed (1000 gal/time period)

Calculations for maximum hourly emissions have been included in Attachment D.

When burning processed animal fat or animal fat blended with distillate oil in the three Cleaver Brooks boilers (B-1, B-2, and B-3), the following equation and emission factors will be used to calculate actual emissions to determine compliance with the hourly and annual limits contained in Conditions III.A.14 and III.A.17 of the permit.

$$E = F \times O \qquad \text{Equation 2}$$

Where:

E	=	Emission Rate (lb/time period)
F	=	Pollutant specific emission factors as follows:

Pollutant	Emission Factor	Emission Factor Units
PM	2.0	lbs/10^3 gallons
PM-10	2.0	
NOx	38.0	
SO2	2.36	
CO	0.46	
VOC	1.8	

O = Processed animal fat consumed (1000 gal/time period)

Previously, it was assumed that the sulfur in processed animal fat was negligible. However, lab fuel testing conducted in 2006 determined that the unblended animal fat contained 0.015 % sulfur. The lab testing conducted on the blended animal fat did not indicate an increase in sulfur content. Since the sulfur content of the processed animal fat is so low, no sulfur monitoring is required. However, fuel supplier certifications, including sulfur content, for the distillate oil that is blended with the animal fat is a monitoring requirement.

The hourly emission limits for each Cleaver Brooks boiler (B-1, B-2, and B-3) were established based on burning processed animal fat when operating at capacity. The annual emission limits for the combined operation of the three boilers are based on the annual throughput limit of 2.0 million gallons of processed animal fat. Therefore, as long as the fuel throughput limit for processed animal fat is not exceeded, there should not be a violation of the hourly or annual emission rates. Calculations have been included in Attachment D to demonstrate how the limits were established.

Hourly emission limits for the Johnston and Superior boilers (B-4 and B-6) were calculated based on maximum rated capacity of each boiler and on the emission factors and higher heating values submitted with VP's application. Total annual emissions for the Johnston and Superior boilers (B-4 and B-6) were based on the combined annual throughput limit of 1.006 million gallons of residual oil and 193.137 million cubic feet of natural gas. As long as the throughput limit for residual oil and natural gas (Condition III.A.7) and the substitution ratio for processed animal fat (Condition III.A.8) are not exceeded, the annual emissions limits should not be exceeded.

The permittee will keep records of monthly and annual throughput of each type of fuel, the quantity of distillate oil and processed animal fat used for each batch of blended animal fat, fuel supplier certifications, sulfur content, all COMS performance evaluations, emissions calculations and DEQ-approved pollutant specific emission factors and equations used to demonstrate compliance with emission limits, fuel specification test results for processed animal fat, weekly inspection log, results of all VEEs and performance tests, all opacity data, written operating procedures, maintenance schedules for the boilers, and operator and training procedure records.

Compliance Assurance Monitoring (CAM)

None of the fuel burning equipment (B-1, B-2, B-3, B-4, and B-6) has add-on control equipment and is therefore not subject to CAM.

Testing

The permit requires stack testing for particulate matter if there is a violation of the opacity standard. Additionally, DEQ can request additional visible emission evaluations on the boilers. The Department and EPA have authority to require testing not included in this permit if necessary to determine compliance with an emission limit or standard.

Reporting

Per 40 CFR 60, Subpart Dc, fuel quality reports for all residual oil shipments for the Superior and Johnston boilers (B-4 and B-6) are required per Condition III.D.1. Also, the permittee is required to submit excess emissions reports for the Johnston boiler (B-6) on a semi-annual basis.

Streamlined Requirements

The 10% opacity limit for the boilers when burning processed animal fat is more stringent than the Virginia Administrative Code Standard for visible emissions, 9 VAC 5-50-80. Therefore, only the more stringent opacity limit was included in the permit.

The 20% opacity limit with no six minute deviation for the boilers (B-1, B-2, and B-3) when burning residual oil or natural gas is more stringent than the Virginia Administrative Code Standard for visible emissions, 9 VAC 5-50-80. Therefore, only the more stringent 20% opacity with no six minute deviation was included in the permit.

The opacity limits for the boilers (B-1, B-2, B-3, B-4, and B-6) are all as or more stringent than Condition 8 of the 1992 Permit for boilers controlling emissions from the feather dryer. These opacity limits include the NSPS, Subpart Dc opacity requirements for boiler (B-6). Therefore, the opacity limit was not included in the permit.

EMISSION UNIT APPLICABLE REQUIREMENTS - Rendering Equipment

Limitations

The following limitations are requirements from the minor NSR permit issued on July 1, 2005, as amended December 11, 2006 and May 23, 2008. Please note that the condition numbers are from that permit; a copy of the permit is included as Attachment B.

Condition 28: Particulate matter and volatile organic compound emissions from the rendering process equipment shall be controlled by wet and chemical scrubbers or incinerated as combustion air in the boilers (B-1, B-2, B-3, B-4, and B-6).

Condition 33: Throughput limit on the amount of material received for rendering.

Condition 34: Throughput limit on amount of raw material input to the Dupps 260J continuous cooker.

Condition 35: Hourly and annual emissions limits from the scrubber controlling the rendering process (PTS-1).

Condition 36: Visible emission limit for the scrubber (PTS-1).

Condition 37: Requires written operating procedures for air pollution control equipment and for operator training.

The following limitations are requirements from the minor NSR permit issued on October 23, 1992. Please note that the condition numbers are from that permit; a copy of the permit is included as Attachment C.

Condition 3: Particulate matter control from the feather dryer (FD-1) by a Venturi scrubber with a design efficiency of 98 %.

Condition 4: Volatile organic compound and odor emissions from the feather dryer (FD-1) equipped with a condenser shall be controlled by a boiler firebox.

Condition 7: Throughput limits for the feather dryer (FD-1).

Condition 14: Requires development of a maintenance schedule and inventory of spare parts for air pollution control equipment.

Condition 15: Requires written operating procedures for air pollution control equipment and for operator training.

The following conditions from the Permit dated October 23, 1992 were not included:

Condition 5: This condition has been fulfilled as the existing feather dryer (at the time the permit was written) was replaced with the new feather dryer.

Condition 9: Notification requirements for the construction and start-up of the new feather dryer have been fulfilled.

Monitoring and Recordkeeping

The monitoring and recordkeeping requirements in Conditions 29, 30, 31, 32, and 39 of the minor NSR permit dated July 1, 2005, as amended December 11, 2006 and May 23, 2008 and the monitoring and recordkeeping requirements in Conditions 3 and 10 of the minor NSR permit dated October 23, 1992 have been modified to meet Part 70 requirements.

Proper operation of the scrubbers and boilers provide reasonable assurance that the particulate matter and volatile organic compound emission and visible emission limits are being met. Proper operation of the boilers is covered in the previous section. Proper operation of the packed tower scrubber (PTS-1) will be monitored by equipping the scrubber with a device to continuously measure the differential pressure across the scrubber. Additionally, the Venturi scrubbers (VS1 and VS2) are equipped with devices to continuously measure the scrubber flow rate and differential pressure across each scrubber. All of these devices are to be observed and logged by the permittee at least once per day.

Valley Proteins will be required to keep records on monthly and annual throughput of material received for rendering, monthly and annual throughput of material processed by the Dupps 260J continuous cooker (CC-2R), annual throughput of wet feather input and feather meal product output, daily monitoring log, manufacturer's specifications for the Venturi scrubber, maintenance, and training.

Compliance Assurance Monitoring (CAM)

Although Units CC-1, CC-2R, FC-1 – FC-5, EC-1, EC-2, and FD-1 are controlled by either boiler incineration, Venturi scrubbers or a packed tower scrubber, the control equipment is primarily for odor control. Additionally, since the entrainment tanks and condensers are considered inherent to the process, uncontrolled particulate and volatile organic compound emissions are less than 100 tons per year. Therefore, CAM does not apply to these units. See Attachment E.

Testing

The permittee may be required to conduct additional VEEs if requested by the Virginia DEQ. The Department and EPA have authority to require testing not included in this permit if necessary to determine compliance with an emission limit or standard. Condition 38 of the minor NSR permit dated 7/1/05, as amended 12/11/06 and 5/23/08, allows for VEE testing upon request by DEQ.

Reporting

No specific reporting has been included in the permit for the process operations.

Streamlined Requirements

There are no requirements that have been streamlined.

GENERAL CONDITIONS

The permit contains general conditions required by 40 CFR Part 70 and 9 VAC 5-80-110 that apply to all Federal operating permitted sources. These include requirements for submitting semi-annual monitoring reports and an annual compliance certification report. The permit also requires notification of deviations from permit requirements or any excess emissions, including those caused by upsets, within four daytime business hours.

STATE ONLY APPLICABLE REQUIREMENTS

The following Virginia Administrative Codes have specific requirements only enforceable by the State and have been identified as applicable by the applicant:

9 VAC 5-50-310, Odorous Emissions.

None of these requirements have been included in the Title V permit.

FUTURE APPLICABLE REQUIREMENTS

The facility has not identified any future applicable requirements in the application. This facility is not a major source of HAPS. Therefore, this facility is not subject to any 40 CFR Part 63 NESHAP standards. In addition, the facility is not subject to any current or proposed area source MACT standards.

INAPPLICABLE REQUIREMENTS

The permittee has not identified any inapplicable requirements in the application.

COMPLIANCE PLAN

Valley Proteins, Inc. - Linville has not been found to be in violation of any state or federal applicable requirements at this time. No compliance plan was included in the application or in the permit.

INSIGNIFICANT EMISSION UNITS

The insignificant emission units are presumed to be in compliance with all requirements of the Clean Air Act as may apply. Based on this presumption, no monitoring, recordkeeping or reporting shall be required for these emission units in accordance with 9 VAC 5-80-110.

Insignificant emission units include the following:

Table V. Insignificant Emission Units

Emission Unit No.	Emission Unit Description	Citation	Pollutant(s) Emitted (9 VAC 5-80-720 B)	Rated Capacity (9 VAC 5-80-720 C)
MS-1, MS-2, MS-3, MS-4, MS-5	five meal storage silos (66,500 cubic feet each)	9 VAC 5-80-720 B	PM and PM-10	---
SS-1, SS-2	two silage storage silos (66,500 cubic feet each)	9 VAC 5-80-720 B	PM and PM-10	---
T-1	distillate oil fuel tank (10,000 gals) Installed in 1974	9 VAC 5-80-720 B	VOC	---
T-2	residual oil fuel tank (20,000 gals) Installed in 1974	9 VAC 5-80-720 B	VOC	---
T-3	residual oil fuel tank (17,000 gals) Installed in 1974	9 VAC 5-80-720 B	VOC	---

Emission Unit No.	Emission Unit Description	Citation	Pollutant(s) Emitted (9 VAC 5-80-720 B)	Rated Capacity (9 VAC 5-80-720 C)
T-4	diesel fuel storage tank (15,000 gals) Installed in 1974	9 VAC 5-80-720 B	VOC	---
T-5	Gasoline storage tank (2,000 gals)	9 VAC 5-80-720 B	VOC	---

[1]The citation criteria for insignificant activities are as follows:
9 VAC 5-80-720 A - Listed Insignificant Activity, Not Included in Permit Application
9 VAC 5-80-720 B - Insignificant due to emission levels
9 VAC 5-80-720 C - Insignificant due to size or production rate

CONFIDENTIAL INFORMATION

Valley Proteins, Inc. did not submit a request for confidentiality. Therefore, all portions of the Title V application are suitable for public review.

PUBLIC PARTICIPATION

A public notice regarding the draft permit was placed in the Daily News-Record, Harrisonburg, Virginia, on November 13, 2009. EPA was sent a copy of the draft permit and notified of the public notice on November 10, 2009. The affected state of West Virginia was sent a copy of the public notice on November 13, 2009. All persons on the Title V mailing list were also sent a copy of the public notice in e-mail dated November 13, 2009.

Public comments were accepted from November 14, 2009 to December 13, 2009. The EPA 45-day comment period ended on December 28, 2009. No comments were received.

ATTACHMENT A

CEDS Emission Inventory Report

Run Date 10/01/2009 11:21:59 AM

Commonwealth of Virginia
Department of Environmental Quality

Registration Number : 80144

County - Plant Id: 165-00023

Plant Name : Valley Proteins Inc - Linville

POLLUTANT EMISSIONS REPORT (STACK/POINT) (TONS/YEAR)

Parameter List

Pollutant Type: All Pollutants
Years: 2008 - 2008

Inventory Year 2008

Stack #: 1

Point #: 25	PM	PM 10	PM 2.5	VOC
Segment #: 1	0.349	0.349	0.349	0.000
	0.349	0.349	0.349	0.000

Point #: 1	CO	NH3	NO2	PM	PM 10	PM 2.5	SO2	VOC
Segment #: 1	3.358	0.537	36.933	10.475	9.257	5.869	126.511	0.188
Segment #: 2	1.890	0.072	2.250	0.171	0.171		0.014	0.124
Segment #: 3	0.024		2.033	0.107	0.107	0.107	0.000	0.096
	5.272	0.609	41.216	10.753	9.535	5.976	126.524	0.408

Point #: 2	CO	NH3	NO2	PM	PM 10	PM 2.5	SO2	VOC
Segment #: 1	0.000		0.000	0.000	0.000	0.000	0.000	0.000
Segment #: 2	0.462		0.550	0.042	0.042	0.042	0.003	0.030
Segment #: 3	0.002		0.152	0.008	0.008		0.000	0.007
Segment #: 4	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	0.464	0.000	0.702	0.050	0.050	0.042	0.003	0.037

Point #: 20	PM	PM 10	PM 2.5	VOC
Segment #: 1	2.068	2.068	0.827	3.483
	2.068	2.068	0.827	3.483

Point #: 21	PM	PM 10	PM 2.5	VOC
Segment #: 1	1.003	1.003	0.401	1.689

Commonwealth of Virginia
Department of Environmental Quality

Registration Number : 80144

County - Plant Id: 165-00023

Plant Name : Valley Proteins Inc - Linville

POLLUTANT EMISSIONS REPORT (STACK/POINT) (TONS/YEAR)

Parameter List

Pollutant Type: All Pollutants
Years: 2008 - 2008

Inventory Year 2008

Stack #: 1

Point #: 21	PM	PM 10	PM 2.5	VOC
	1.003	1.003	0.401	1.689

Point #: 22	PM	PM 10	VOC
Segment #: 1	0.030	0.030	0.152
	0.030	0.030	0.152

Point #: 23	PM	PM 10	PM 2.5	VOC
Segment #: 1	0.349	0.349	0.349	1.468
	0.349	0.349	0.349	1.468

Stack #: 2

Point #: 3	CO	NH3	NO2	PM	PM 10	PM 2.5	SO2	VOC
Segment #: 1	0.183	0.029	0.730	0.073	0.037	0.057	2.592	0.007
Segment #: 2	0.000		0.000	0.000	0.000			0.000
	0.183	0.029	0.730	0.073	0.037	0.057	2.592	0.007

Stack #: 3

Point #: 26	CO	NO2	PM	PM 10	PM 2.5	SO2	VOC
Segment #: 1	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Segment #: 2	2.898	3.450	0.262	0.262	0.262	0.021	0.190
Segment #: 3	0.027	2.223	0.115	0.117	0.117	0.000	0.105
	2.925	5.673	0.378	0.379	0.379	0.021	0.295

Registration Number: 80144

County - Plant ID: 165-00023

Plant Name: Valley Proteins Inc - Linville

ROAD MAP REPORT

Inventory Year: 2008

Stack #: 1 Stack 1 Description

Point #: 1 Cleaver Brooks Boilers 1 - 3

- Segment #: 1 Residual oil
- Segment #: 2 Natural Gas
- Segment #: 3 Animal Fat

Point #: 2 Superior Boiler 4

- Segment #: 1 Residual Oil
- Segment #: 2 Natural Gas
- Segment #: 3 Processed Animal Fat
- Segment #: 4 #4 Oil

Point #: 20 Point 020 Description

- Segment #: 1 CONTINUOUS COOKER 320U

Point #: 21 Point 021 Description

- Segment #: 1 CONTINUOUS COOKER DUPPS 260J

Point #: 22 Point 022 Description

- Segment #: 1 EGG SHELL COOKERS 1 & 2

Point #: 23 Point 023 Description

- Segment #: 1 BATCH FEATHER COOKERS 1-5

Point #: 25 Point 025 Description

- Segment #: 1 FEATHER DRYER

Stack #: 2 Stack 2 Description

Point #: 3 Point 003 Description

- Segment #: 1 CLVR BRKS/CB200 - Boiler #5
- Segment #: 2 CLVR BRKS/CB200

Stack #: 3 Stack 3 Johnston Boiler Stack

Registration Number: 80144

County - Plant ID: 165-00023

Plant Name: Valley Proteins Inc - Linville

ROAD MAP REPORT

Inventory Year: 2008

Stack #: 3

Point #: 26 Johnston Boiler

Segment #: 1	Johnston Boiler-Residual Oil
Segment #: 2	Johnston Boiler-Natural Gas
Segment #: 3	Johnston Boiler-Animal Fat

ATTACHMENT B

Minor NSR Permit
(dated July 1, 2005, as amended December 11, 2006 and May 23, 2008)

COMMONWEALTH *of* VIRGINIA

DEPARTMENT OF ENVIRONMENTAL QUALITY

VALLEY REGIONAL OFFICE
4411 Early Road. P.O. Box 3000, Harrisonburg, Virginia 22801
(540) 574-7800 Fax (540) 574-7878
www.deq.virginia.gov

L. Preston Bryant, Jr.
Secretary of Natural Resources

David K. Paylor
Director

Amy Thatcher Owens
Regional Director

May 27, 2008

Mr. Thomas A. Gibson, Jr.
Director of Environmental Affairs
Valley Proteins, Inc. - Linville
6230 Kratzer Road
Linville, VA 22834

Location: Rockingham County
Registration No.: 80144
Plant ID No.: 51-165-0023

Dear Mr. Gibson:

Attached is a minor amendment to your new source review permit dated December 11, 2006 to modify and operate a rendering facility in accordance with the provisions of the Commonwealth of Virginia Regulations for the Control and Abatement of Air Pollution. Permit changes are reflected in Conditions 10, 50, 51, 56, and 68. This permit replaces your permit dated December 11, 2006.

This permit contains legally enforceable conditions. Failure to comply may result in a Notice of Violation and civil penalty. <u>Please read all permit conditions carefully</u>.

The Department of Environmental Quality (DEQ) deemed the application complete on April 17, 2008 and has determined that the application meets the requirements of 9 VAC 5-80-1280.A. for a minor amendment to a new source review permit.

This permit approval to modify and operate shall not relieve Valley Proteins, Inc. - Linville of the responsibility to comply with all other local, state, and federal permit regulations.

The Board's Regulations, as contained in Title 9 of the Virginia Administrative Code 5-170-200, provides that you may request a formal hearing from this case decision by filing a petition with the Board within 30 days after this case decision notice was mailed or delivered to you. 9 VAC 5-170-200 provides that you may request direct consideration of the decision by the

Board if the Director of the DEQ made the decision. Please consult the relevant regulations for additional requirements for such requests.

As provided by Rule 2A:2 of the Supreme Court of Virginia, you have 30 days from the date you actually received this permit or the date on which it was mailed to you, whichever occurred first, within which to initiate an appeal of this decision by filing a Notice of Appeal with:

David K. Paylor, Director
Department of Environmental Quality
P. O. Box 1105
Richmond, VA 23218

If this permit was delivered to you by mail, three days are added to the period in which to file an appeal. Please refer to Part Two A of the Rules of the Supreme Court of Virginia for information on the required content of the Notice of Appeal and for additional requirements governing appeals from decisions of administrative agencies.

If you have any questions concerning this permit, please call Kevin Covington of the Valley Regional Office at (540) 574-7881.

Sincerely,

Larry M. Simmons

Larry M. Simmons, P.E.
Deputy Regional Director

Attachment: Permit
Source Testing Report Format
Opacity Monitoring Report Format
NSPS, Subpart Dc

Cc: Director, OAPP (electronic file submission)
Chief, Air Enforcement Branch (3AP13), U.S. EPA, Region III

COMMONWEALTH of VIRGINIA

DEPARTMENT OF ENVIRONMENTAL QUALITY

VALLEY REGIONAL OFFICE
4411 Early Road, P.O. Box 3000, Harrisonburg, Virginia 22801
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L. Preston Bryant, Jr.
Secretary of Natural Resources

David K. Paylor
Director

Amy Thatcher Owens
Regional Director

STATIONARY SOURCE PERMIT TO MODIFY AND OPERATE

This permit includes designated equipment subject to New Source Performance Standards (NSPS)

This permit replaces your permit dated July 1, 2005, as amended December 11, 2006.

In compliance with the Federal Clean Air Act and the Commonwealth of Virginia Regulations for the Control and Abatement of Air Pollution,

Valley Proteins, Inc. - Linville
6230 Kratzer Road
Linville, VA 22834
Registration No.: 80144
Plant ID No.: 51-165-0023

is authorized to modify and operate:

a rendering facility

located at:

6230 Kratzer Road
Rockingham County, Virginia

in accordance with the Conditions of this permit.

Approved on: July 1, 2005

Amended on: December 11, 2006

Amended on: May 23, 2008

Deputy Regional Director, Valley Region

Permit consists of 19 pages.
Permit Conditions 1 to 68.

INTRODUCTION

This permit approval is based on the permit applications dated April 16, 2008, October 11, 2006, March 11, 2005, October 2, 2000, and May 28, 1974, including amended pages dated June 6, 2005, March 24, 2005 and including supplemental information dated April 29, 2005, April 21, 2005, April 12, 2005, March 17, 2005, February 21, 2001 and March 5, 2001. Any changes in the permit application specifications or any existing facilities which alter the impact of the facility on air quality may require a permit. Failure to obtain such a permit prior to construction may result in enforcement action.

Words or terms used in this permit shall have meanings as provided in 9 VAC 5-10-20 of the State Air Pollution Control Board Regulations for the Control and Abatement of Air Pollution. The regulatory reference or authority for each condition is listed in parentheses () after each condition.

Annual requirements to fulfill legal obligations to maintain current stationary source emissions data will necessitate a prompt response by the permittee to requests by the DEQ or the Board for information to include, as appropriate: process and production data; changes in control equipment; and operating schedules. Such requests for information from the DEQ will either be in writing or by personal contact.

The availability of information submitted to the DEQ or the Board will be governed by applicable provisions of the Freedom of Information Act, §§ 2.2-3700 through 2.2-3714 of the Code of Virginia, § 10.1-1314 (addressing information provided to the Board) of the Code of Virginia, and 9 VAC 5-170-60 of the State Air Pollution Control Board Regulations. Information provided to federal officials is subject to appropriate federal law and regulations governing confidentiality of such information.

PROCESS REQUIREMENTS

1. **Equipment List** - Equipment at this facility consists of the following:

Equipment to be operated			
Reference No.	**Equipment Description**	**Rated Capacity**	**Federal Requirements**
B-1 – B-3	Three Cleaver Brooks boilers	29.291 MMBtu/hr each	---
B-4	Superior 4-S-3004 boiler	25 MMBtu/hr	---
B-6	Johnston Series 509 boiler	48.4 MMBtu/hr	NSPS Subpart Dc
CC-1	Dupps 320U continuous cooker equipped with a cyclone entrainment tank and shell & tube condenser/or air cooled condensers	22.5 tons/hr maximum solids input	---
CC-2R	Dupps 260J continuous cooker equipped with a cyclone entrainment tank and shell & tube condenser	18.1 tons/hr	---
FC-1 – FC-5	Five Dupps 5x12 feather cookers equipped with a cyclone entrainment tank and a direct contact condenser	1.75 tons/hr maximum solids input each	---
EC-1 – EC-2	Two Dupps 5x16 eggshell cookers equipped with a cyclone entrainment tank and a direct contact condenser	3.5 tons/hr maximum solids input each	---

Reference No.	Equipment Description	Rated Capacity	Federal Requirements
---	Cooker process equipment including but not limited to drainers, pressers, screens, sedimentors, and centrifuges	---	---

(9 VAC 5-80-1180 D 3)

OPERATING/EMISSION LIMITATIONS – FUEL BURNING EQUIPMENT

2. **Operating Restriction** – The Cleaver Brooks CB200 boiler (Ref. B-5) shall not supply steam or heat to the Valley Proteins, Inc. – Linville rendering facility.
(9 VAC 5-80-1180)

3. **Operating Restriction** – Only the Johnston boiler (Ref. B-6) shall provide steam for the Dupps 260J continuous cooker (Ref. CC-2R). When the Johnston boiler is not operating, the Superior boiler (Ref. B-4) may provide steam for the Dupps 260J continuous cooker (Ref. CC-2R).
(9 VAC 5-80-1180)

4. **Operating Restriction** – The Superior boiler (Ref. B-4) may provide steam as a back up to any one of the three Cleaver Brooks boilers (Ref. B-1, B-2, and B-3). Fuel consumed by the Superior boiler (Ref. B-4) when backing up the Cleaver Brooks boilers shall be included in the fuel throughput limit contained in Condition 8.
(9 VAC 5-80-1180)

5. **Fuel** – The approved fuels for the boilers (Ref. B-1-B-3, B-4 and B-6) are residual oil, natural gas, and processed animal fat. A change in the fuels may require a permit to modify and operate.
(9 VAC 5-80-1180)

6. **Fuel** – The processed animal fat may be blended with distillate oil. The ratio shall consist of a maximum of 10 gallons of distillate oil per 6500 gallons of processed animal fat.
(9 VAC 5-80-1180)

7. **Fuel Throughput** – Total combined annual fuel throughput for the Cleaver Brooks boilers (Ref. B-1, B-2 and B-3) shall be limited to no more than 2.0 million gal/yr of processed animal fat, calculated monthly as the sum of each consecutive 12-month period.
(9 VAC 5-80-1180)

8. **Fuel Throughput** - Total combined annual fuel throughput for the Johnston and Superior boilers (Ref. B-4 and B-6) shall be limited to no more than 1,006,000 gallons per year of residual oil and 193.137 million cubic feet of natural gas per year, calculated monthly as the sum of each consecutive 12-month period.
(9 VAC 5-80-1180)

9. **Fuel Throughput** – The permittee may substitute processed animal fat as a fuel for boiler B-4 or B-6 in accordance with the following methodology. The substitution ratio shall be 1.44

gallons of processed animal fat for each gallon of residual oil or 2,600 gallons of processed animal fat for each one million cubic feet of natural gas (i.e., for each gallon of animal fat burned, the allowable annual throughputs in Condition 8 shall be decreased by 0.69 gallon for residual oil or 0.000385 million cubic feet for natural gas). In no case shall the total processed animal fat consumed in boiler B-6 exceed 1,950,796 gallons of processed animal fat per year, calculated monthly as the sum of each consecutive 12-month period.
(9 VAC 5-80-1180)

10. **Fuel Specifications** – The residual oil burned in the boilers (Ref. B-4 and B-6) shall meet the specifications below:

    RESIDUAL OIL which meets the ASTM D396 specifications for numbers 4, 5, or 6 fuel oil:

    Maximum sulfur content calculated on a 30-day rolling average basis: 0.5%

    (9 VAC 5-80-1180, 9 VAC 5-50-260, 40 CFR 60.42c (d) and 40 CFR 60.42c (g))

11. **Fuel Specifications** - The distillate oil and processed animal fat shall meet the specifications below:

    DISTILLATE OIL which meets the ASTM D396 specification for numbers 1 or 2 fuel oil:
    Maximum sulfur content per shipment: 0.05%

    Processed animal fats derived from Valley Proteins, Inc. rendering operations.

    (9 VAC 5-80-1180)

12. **Fuel Certification** - The permittee shall sample and analyze the residual oil tank(s) serving the boilers (Ref. B-4 and B-6) initially before startup of the boilers and immediately after each shipment of residual oil is added to the tank in accordance with 40 CFR 60.46c (d)(2). The permittee shall maintain records of all oil analyses and of all oil shipments purchased. These records shall be available for inspection by the DEQ. Such records shall be current for the most recent five years.
(9 VAC 5-80-1180 and 40 CFR 60.44c (g))

13. **Fuel Certification** - The permittee shall obtain a certification from the fuel supplier with each shipment of distillate oil. Each fuel supplier certification shall include the following:

    a. The name of the fuel supplier;

    b. The date on which the distillate oil was received;

    c. The quantity of distillate oil delivered in the shipment;

    d. A statement that the distillate oil complies with the American Society for Testing and Materials specifications (ASTM D396) for number 2 fuel oil; and

e. The sulfur content of the distillate oil;

Fuel sampling and analysis, independent of that used for certification, as may be periodically required or conducted by DEQ may be used to determine compliance with the fuel specifications stipulated in Condition 11. Exceedance of these specifications may be considered credible evidence of the exceedance of emission limits.
(9 VAC 5-80-1180)

14. **Operating and Training Procedures** - Boiler emissions shall be controlled by proper operation and maintenance of combustion equipment. Boiler operators shall be trained in the proper operation of all such equipment. Training shall consist of a review and familiarization of the manufacturer's operating instructions, at minimum. The permittee shall maintain records of the required training including a statement of time, place and nature of training provided. The permittee shall have available good written operating procedures and a maintenance schedule for the boiler. These procedures shall be based on the manufacturer's recommendations, at minimum. All records required by this condition shall be kept on site and made available for inspection by the DEQ.
(9 VAC 5-80-1180)

15. **Short-Term Emission Limits: Processed Animal Fat** - Emissions from the operation of each of the three Cleaver Brooks boilers (B-1, B-2 and B-3) when burning processed animal fat shall not exceed the limits specified below:

Particulate Matter	0.45	lbs/hr
PM-10	0.45	lbs/hr
Sulfur Dioxide	0.53	lbs/hr
Nitrogen Dioxide	8.54	lbs/hr
Carbon Monoxide	0.10	lbs/hr
Volatile Organic Compounds	0.40	lbs/hr

(9 VAC 5-80-1180 and 9 VAC 5-50-260)

16. **Short-Term Emission Limits: All Fuels** - Emissions from the operation of the Johnston boiler (B-6) shall not exceed the limits specified below:

Particulate Matter	2.52	lbs/hr
PM-10	2.19	lbs/hr
Sulfur Dioxide	25.33	lbs/hr

Nitrogen Dioxide	17.75	lbs/hr
Carbon Monoxide	3.93	lbs/hr
Volatile Organic Compounds	0.67	lbs/hr

(9 VAC 5-80-1180 and 9 VAC 5-50-260)

17. **Short-Term Emission Limits: All Fuels** - Emissions from the operation of the Superior boiler (B-4) shall not exceed the limits specified below:

Particulate Matter	1.30	lbs/hr
PM-10	1.13	lbs/hr
Sulfur Dioxide	13.08	lbs/hr
Nitrogen Dioxide	9.17	lbs/hr
Carbon Monoxide	2.03	lbs/hr
Volatile Organic Compounds	0.35	lbs/hr

(9 VAC 5-80-1180 and 9 VAC 5-50-260)

18. **Annual Emissions Limits: Processed Animal Fat** – Total emissions from the operation of the three Cleaver Brooks boilers (B-1, B-2 and B-3) when burning processed animal fat shall not exceed the limits specified below:

Particulate Matter	2.00	tons/yr
PM-10	2.00	tons/yr
Sulfur Dioxide	2.36	tons/yr
Nitrogen Dioxide	38.00	tons/yr
Carbon Monoxide	0.46	tons/yr
Volatile Organic Compounds	1.80	tons/yr

Annual emissions shall be calculated monthly as the sum of each consecutive 12-month period.
(9 VAC 5-80-1180 and 9 VAC 5-50-260)

19. **Annual Emissions Limits: All Fuels** – Total emissions from the operation of the Johnston and Superior boilers (Ref. B-4 and B-6) shall not exceed the limits specified below:

Particulate Matter	4.66	tons/yr
PM-10	4.15	tons/yr
Sulfur Dioxide	39.54	tons/yr
Nitrogen Dioxide	37.32	tons/yr
Carbon Monoxide	10.63	tons/yr
Volatile Organic Compounds	1.76	tons/yr

Annual emissions shall be calculated monthly as the sum of each consecutive 12-month period.
(9 VAC 5-80-1180 and 9 VAC 5-50-260)

20. **Visible Emission Limit** - Visible emissions from the three Cleaver Brooks boiler (Ref. B1-B-3) stacks when burning processed animal fat shall not exceed 10 percent opacity except during one six-minute period in any one hour in which visible emissions shall not exceed 20 percent opacity as determined by EPA Method 9 (reference 40 CFR Part 60, Appendix A). This condition applies at all times except during startup, shutdown, and malfunction.
(9 VAC 5-80-1180, 9 VAC 5-50-80, and 9 VAC 5-50-260)

21. **Visible Emission Limit** - Visible emissions from the three Cleaver Brooks boiler (Ref. B-1 – B-3) stacks when burning residual oil or natural gas shall not exceed 20 percent opacity as determined by EPA Method 9 (reference 40 CFR Part 60, Appendix A). This condition applies at all times except during startup, shutdown, and malfunction.
(9 VAC 5-80-1180, 9 VAC 5-50-80, and 9 VAC 5-80-1180)

22. **Visible Emission Limit** - Visible emissions from the Johnston boiler (Ref. B-6) and the Superior boiler (Ref. B-4) stacks when burning processed animal fat or natural gas shall not exceed 10 percent opacity except during one six-minute period in any one hour in which visible emissions shall not exceed 20 percent opacity as determined by EPA Method 9 (reference 40 CFR Part 60, Appendix A). This condition applies at all times except during startup, shutdown, and malfunction.
(9 VAC 5-80-1180, 9 VAC 5-50-80, and 9 VAC 5-50-260)

23. **Visible Emission Limit** - Visible emissions from the Johnston boiler (Ref. B-6) when burning residual oil shall not exceed 20 percent opacity except during one six-minute period in any one hour in which visible emissions shall not exceed 27 percent opacity as determined by EPA Method 9 (reference 40 CFR Part 60, Appendix A). This condition applies at all times except during startup, shutdown, and malfunction.
(9 VAC 5-80-1180, 9 VAC 5-50-80, 9 VAC 5-50-260, and 40 CFR 60.43c)

24. **Visible Emission Limit -** Visible emissions from the Superior boiler (Ref. B-4) when burning residual oil shall not exceed 20 percent opacity except during one six-minute period in any one hour in which visible emissions shall not exceed 30 percent opacity as determined by EPA Method 9 (reference 40 CFR Part 60, Appendix A). This condition applies at all times except during startup, shutdown, and malfunction.
(9 VAC 5-80-1180, 9 VAC 5-50-80, and 9 VAC 5-50-260)

25. **Requirements by Reference -** Except where this permit is more restrictive than the applicable requirement, the Johnston boiler (Ref. B-6) shall be operated in compliance with the requirements of 40 CFR 60, Subpart Dc.
(9 VAC 5-80-1180, 9 VAC 5-50-400, and 9 VAC 5-50-410)

<u>COMS – FUEL BURNING EQUIPMENT</u>

26. **COMS: Johnston Boiler (Ref. B-6) Stack (Stack Ref. B6E-1)** – A continuous opacity monitor (COMS) shall be installed to measure and record opacity from the Johnston boiler stack (Stack Ref. B6E-1). The opacity monitor shall monitor and record the opacity of the emissions discharged to the atmosphere when the Johnston boiler (Ref. B-6) is burning residual oil. The monitor shall be maintained, located, and calibrated in accordance with the applicable procedures under Performance Specification 1 of 40 CFR Part 60, Appendix B.
(9 VAC 5-50-30 and 40 CFR 60.47c (b)) and 40 CFR 60.13)

27. **COMS: Johnston boiler (Ref. B-6)** – The span value of the COMS shall be set at the following:

Monitor	Fuel Type	Span
COMS (Opacity)	Residual Oil	60%-80%

(9 VAC 5-50-30 and 40 CFR 60.47c (b))

<u>PROCESS REQUIREMENTS – RENDERING EQUIPMENT</u>

28. **Emission Controls** – Particulate matter and volatile organic compound emissions from the rendering process equipment shall be controlled by wet and chemical scrubbers or incinerated as combustion air in the boilers (B-1, B-2, B-3, B-4, B-6) as follows:

    a. Emissions from the following equipment shall be controlled by a 10,000 cfm Venturi scrubber (VS2) and a 15,000 cfm packed tower scrubber (PTS-1) operated in series:

       – All cooker process equipment including, but not limited to: drainers, pressers, screens, sedimentors, and centrifuges.

b. Non-condensable emissions from the following equipment shall be controlled by a 5,000 cfm Venturi scrubber (VS1) and then incinerated as combustion air in the boilers (B-1, B-2, B-3, B-4, B-6):

- The Dupps 320 U continuous cooker (CC-1), the Dupps 260J continuous cooker, the two eggshell cookers (EC-1, EC-2), and the five batch feather cookers (FC-1 – FC-5).

Whenever the boiler(s) is not available, these emissions shall pass through the 15,000 cfm packed tower scrubber (PTS-1). The bypass of the boilers is permitted only during times when the boilers are operating at a firing load of less than 20 percent.
(9 VAC 5-50-260 and 9 VAC 5-80-1180)

29. **Monitoring Devices** - The packed tower scrubber (PTS-1) shall be equipped with a device to continuously measure the differential pressure across the scrubber (PTS-1). The monitoring device shall be installed, maintained, calibrated and operated in accordance with approved procedures which shall include, as a minimum, the manufacturer's written requirements or recommendations. The monitoring device shall be provided with adequate access for inspection and shall be in operation when the packed tower scrubber (PTS-1) is operating.
(9 VAC 5-80-1180 and 9 VAC 5-50-20 C)

30. **Monitoring Device Observation** - The monitoring devices used to continuously measure the differential pressure across the packed tower scrubber (PTS-1) shall be observed by the permittee with a frequency of not less than once per day. The permittee shall keep a log of the observations from the packed tower scrubber (PTS-1).
(9 VAC 5-80-1180 and 9 VAC 5-50-20 C)

31. **Monitoring Devices** – Each Venturi scrubber (VS1 and VS2) shall be equipped with a device to continuously measure the scrubber flow rate and differential pressure across the scrubber. Each monitoring device shall be installed, maintained, calibrated and operated in accordance with approved procedures which shall include, as a minimum, the manufacturer's written requirements or recommendations. Each monitoring device shall be provided with adequate access for inspection and shall be in operation when the Venturi scrubbers (VS1 and VS2) are operating.
(9 VAC 5-80-1180 and 9 VAC 5-50-20 C)

32. **Monitoring Device Observation** - The monitoring devices used to continuously measure the Venturi scrubbers' flow rate and differential pressure (VS1 and VS2) shall be observed by the permittee with a frequency of not less than once per day. The permittee shall keep a log of the observations from the Venturi scrubbers (VS1 and VS2).
(9 VAC 5-80-1180 and 9 VAC 5-50-20 C)

OPERATING/EMISSION LIMITATIONS – RENDERING EQUIPMENT

33. **Production Throughput** - The total amount of material received for rendering for the facility shall not exceed 465,390 tons per year, calculated monthly as the sum of each consecutive 12-month period.
(9 VAC 5-80-1180)

34. **Production Throughput** - The total amount of raw material input to the Dupps 260J continuous cooker shall not exceed 130,320 tons per year, calculated monthly as the sum of each consecutive 12-month period.
(9 VAC 5-80-1180)

35. **Emission Limits** – Total emissions from the scrubber controlling the rendering process (PTS-1) shall not exceed the limits specified below:

Particulate Matter	2.68 lbs/hr	11.05 tons/yr
Volatile Organic Compounds	4.51 lbs/hr	18.62 tons/yr

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits shall be considered credible evidence of the exceedance of emission limits. Compliance with these limits shall be determined as stated in Conditions 33 and 36.
(9 VAC 5-50-260 and 9 VAC 5 80-1180)

36. **Visible Emission Limit** - Visible emissions from the scrubber (PTS-1) shall not exceed 20 percent opacity except during one six-minute period in any one hour in which visible emissions shall not exceed 30 percent opacity as determined by EPA Method 9 (reference 40 CFR Part 60, Appendix A). Failure to meet specified limits due to the presence of water vapor shall not be a violation of that limit. This condition applies at all times except during startup, shutdown, and malfunction.
(9 VAC 5-50-80, 9 VAC 5-50-260 and 9 VAC 5-80-1180)

MAINTENANCE AND MALFUNCTION REQUIREMENTS

37. **Operating Procedures and Operator Training** - The permittee shall have available written operating procedures for all air pollution control equipment. These procedures shall be based on the manufacturer's recommendations, at a minimum. All air pollution control operators shall be trained and certified in the proper operation of all such equipment. The permittee shall maintain records of the required training and certification. Certification of training shall consist of a statement of time, place, and nature of training provided. The permittee shall operate in accordance with the written operating procedures for all air pollution control equipment. The permittee shall review the operating procedures annually. The date of this review and any operational changes shall be documented and made available for DEQ inspection.
(9 VAC 5-80-1180)

CONTINUING COMPLIANCE DETERMINATION

38. **Visible Emissions Evaluations** - Upon request by the DEQ, the permittee shall conduct additional visible emission evaluations from the two boilers (B-4 and B-6) and the packed tower scrubber (PTS-1) to demonstrate compliance with the visible emission limits contained in this permit. The details of the tests shall be arranged with the Director, Valley Regional Office..
(9 VAC 5-80-1200 and 9 VAC 5-50-30 G)

RECORDKEEPING AND REPORTING REQUIREMENTS

39. **On Site Records** - The permittee shall maintain records of emission data and operating parameters as necessary to demonstrate compliance with this permit. The content and format of such records shall be arranged with the Director, Valley Regional Office. These records shall include, but are not limited to:

    a. The monthly and annual throughput of processed animal fat (gallons) for the Cleaver Brooks boilers (Ref. B-1, B-2 and B-3). Annual throughput shall be calculated monthly as the sum of each consecutive 12-month period.

    b. The daily, monthly, and annual throughput of residual oil (gallons), natural gas (million cubic feet), and processed animal fat (gallons) for the Johnston boiler (Ref. B-6). Annual throughput shall be calculated monthly as the sum of each consecutive 12-month period.

    c. The monthly and annual throughput of residual oil (gallons), natural gas (million cubic feet), and processed animal fat (gallons) for the Superior boiler (Ref. B-4). Annual throughput shall be calculated monthly as the sum of each consecutive 12-month period.

    d. The quantity of distillate oil and processed animal fat used in producing the blended animal fat for each batch blended.

    e. The monthly and annual throughput of material received for rendering (in tons) for the facility. Annual throughput shall be calculated monthly as the sum of each consecutive 12-month period.

    f. The monthly and annual throughput of material (in tons) processed by the Dupps 260J continuous cooker (CC-2R). Annual throughput shall be calculated monthly as the sum of each consecutive 12-month period.

    g. Records of all oil analyses and of all oil shipments purchased.

    h. Fuel specification test results and certifications including sulfur content and heating value for the distillate oil.

    i. All COMS performance evaluations and visible emission evaluations.

j. A log of daily monitoring device observations as required by Conditions 30 and 32 to include differential pressure on the packed tower scrubber (Ref. PTS-1) and the flow rate and differential pressure for the Venturi scrubbers (VS1 and VS2).

k. Monthly emissions calculations demonstrating compliance with the annual emissions limitations in Conditions 18 and 19.

l. All opacity data.

m. Operator and training procedure records as required by Conditions 14 and 37.

These records shall be available on site for inspection by the DEQ and shall be current for the most recent five years.
(9 VAC 5-80-1180, 9 VAC 5-50-50, and 40 CFR 60.48c)

40. **Semi-Annual Reports** - The permittee shall submit fuel quality reports to the Director, Valley Regional Office, postmarked no later than the 30th day following the end of the semi-annual period. If no shipments of residual oil were received during the semi-annual period, the semi-annual report shall consist of the dates included in the semi-annual period and a statement that no oil was received during the semi-annual period. If residual oil was received during the semi-annual period, the reports shall include:

a. The dates included in the semi-annual period,

b. A summary of all oil shipments purchased for the Superior and Johnston boilers (Ref. B-4 and B-6) indicating the supplier, volume of the shipment, and date on which the shipment was made;

c. Each 30-day average sulfur content (weight percent) calculated during the reporting period, ending with the last 30-day period;

d. Reasons for any noncompliance with the emission standards and a description of corrective actions taken; and

e. A summary of all subsequent oil analyses indicating the sampling dates, sulfur content of the oil and method used to sample and analyze the oil.

One copy of the semi-annual report shall be submitted to:

Associated Director
Offices of Air Enforcement (3AP10)
U.S. Environmental Protection Agency
Region III
1650 Arch Street
Philadelphia, PA 19103-2029

(9 VAC 5-80-1180, 9 VAC 5-50-50 and 40 CFR 60.48c)

41. **Reports for Continuous Monitoring Systems** – The permittee shall submit excess emissions reports to the Director, Valley Regional Office, for the Johnston boiler (Ref. B-6) on a semi-annual basis, postmarked no later than the 30^{th} day following the end of the semi-annual period. These reports shall include, but are not limited to the following information:

   a. The magnitude of excess emissions, any conversion factors used in the calculation of excess emissions, and the date and time of commencement and completion of each period of excess emissions;

   b. Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the process, the nature and cause of the malfunction (if known), the corrective action taken or preventative measures adopted;

   c. The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments; and

   d. When no excess emissions have occurred or the continuous monitoring systems have not been inoperative, repaired or adjusted, such information shall be stated in that report.

   One copy of the semi-annual report shall be submitted to the U.S. Environmental Protection Agency at the address specified in Condition 40.
   (9 VAC 5-80-1180, 9 VAC 5-50-50 and 40 CFR 60.48c)

GENERAL CONDITIONS

42. **Permit Suspension/Revocation** - This permit may be suspended or revoked if the permittee:

   a. Knowingly makes material misstatements in the permit application or any amendments to it;

   b. Fails to comply with the conditions of this permit;

   c. Fails to comply with any emission standards applicable to a permitted emissions unit;

   d. Causes emissions from the stationary source which result in violations of, or interfere with the attainment and maintenance of, any ambient air quality standard; or

   e. Fails to operate in conformance with any applicable control strategy, including any emission standards or emission limitations, in the State Implementation Plan in effect at the time an application for this permit is submitted.

   (9 VAC 5-80-1210 F)

43. **Right of Entry** - The permittee shall allow authorized local, state and federal representatives, upon the presentation of credentials:

    a. To enter upon the upon the permittee's premises on which the facility is located or in which any records are required to be kept under the terms and conditions of this permit;

    b. To have access to and copy at reasonable times any records required to be kept under the terms and conditions of this permit or the State Air Pollution Control Board Regulations;

    c. To inspect at reasonable times any facility, equipment, or process subject to the terms and conditions of this permit or the State Air Pollution Control Board Regulations; and

    d. To sample or test at reasonable times.

    For purposes of this condition, the time for inspection shall be deemed reasonable during regular business hours or whenever the facility is in operation. Nothing contained herein shall make an inspection time unreasonable during an emergency.
    (9 VAC 5-170-130 and 9 VAC 5-80-1180)

44. **Record of Malfunctions** - The permittee shall maintain records of the occurrence and duration of any bypass, malfunction, shutdown or failure of the facility or its associated air pollution control equipment that results in excess emissions for more than one hour. Records shall include the date, time, duration, description (emission unit, pollutant affected, cause), corrective action, preventive measures taken and name of person generating the record.
    (9 VAC 5-20-180 J and 9 VAC 5-80-1180 D)

45. **Notification for Facility or Control Equipment Malfunction** - The permittee shall furnish notification to the Director, Valley Regional Office, of malfunctions of the affected facility or related air pollution control equipment that may cause excess emissions for more than one hour, by facsimile transmission, telephone or telegraph. Such notification shall be made as soon as practicable but not later than four daytime business hours after the malfunction is discovered. The permittee shall provide a written statement giving all pertinent facts, including the estimated duration of the breakdown, within 14 days of the discovery. When the condition causing the failure or malfunction has been corrected and the equipment is again in operation, the permittee shall notify Director, Valley Regional Office, in writing.
    (9 VAC 5-20-180 C and 9 VAC 5-80-1180)

46. **Violation of Ambient Air Quality Standard** - The permittee shall, upon request of the DEQ, reduce the level of operation or shut down a facility, as necessary to avoid violating any primary ambient air quality standard and shall not return to normal operation until such time as the ambient air quality standard will not be violated.
    (9 VAC 5-20-180 I and 9 VAC 5-80-1180)

47. **Change of Ownership** - In the case of a transfer of ownership of a stationary source, the new owner shall abide by any current permit issued to the previous owner. The new owner shall

notify the Director, Valley Regional Office, of the change in ownership within 30 days of the transfer.
(9 VAC 5-80-1240)

48. **Permit Copy** - The permittee shall keep a copy of this permit on the premises of the facility to which it applies.
(9 VAC 5-80-1180)

STATE-ONLY ENFORCEABLE REQUIREMENTS

This section is included pursuant to 9 VAC 5-80-1120 F, and is not required under the federal Clean Air Act or under any of its applicable federal requirements. This section is only enforceable by the Commonwealth of Virginia State Air Pollution Control Board and its designees.

ODOR CONTROL PROCESS REQUIREMENTS

49. **Emission Controls** – Odorous emissions from the rendering process equipment shall be controlled by wet and chemical scrubbers or incinerated as combustion air in the boilers (B-1, B-2, B-3, B-4, B-6) as follows:

   a. Emissions from the following equipment shall be controlled by a 10,000 cfm Venturi scrubber (VS2) and a 15,000 cfm packed tower scrubber (PTS-1) operated in series:

      – All cooker process equipment including, but not limited to: drainers, pressers, screens, sedimentors, and centrifuges.

   b. Non-condensable emissions from the following equipment shall be controlled by a 5,000 cfm Venturi scrubber (VS1) and then incinerated as combustion air in the boilers (B-1, B-2, B-3, B-4, B-6):

      – The Dupps 320 U continuous cooker (CC-1), the Dupps 260J continuous cooker, the two eggshell cookers (EC-1, EC-2), and the five batch feather cookers (FC-1 – FC-5).

   Whenever the boiler(s) is not available, these emissions shall pass through the 15,000 cfm packed tower scrubber (PTS-1). The bypass of the boilers is permitted only during times when the boilers are operating at a firing load of less than 20 percent.
   (9 VAC 5-50-140 and 9 VAC 5-80-1180)

50. **Emission Controls** – A positive oxidation-reduction potential (ORP) shall be maintained at all times when exhaust gases are directed to the scrubber (PTS-1). Approved scrubbing chemicals are chlorine dioxide and ZA300 HS, which is a proprietary solution with a primary active ingredient of potassium monopersulfate (KMPS).
(9 VAC 5-50-140 and 9 VAC-5-80-1180)

51. **Monitoring Devices** - The packed tower scrubber (PTS-1) shall be equipped with a device to continuously measure the oxidation-reduction potential (ORP) of the scrubbing chemical used in the scrubber (PTS-1). The monitoring device shall be installed, maintained, calibrated and operated in accordance with approved procedures which shall include, as a minimum, the manufacturer's written requirements or recommendations. The monitoring device shall be provided with adequate access for inspection and shall be in operation when the packed tower scrubber (PTS-1) is operating.
(9 VAC 5-50-140 and 9 VAC-5-80-1180)

52. **Monitoring Device Observation** - The monitoring devices used to continuously measure the scrubber ORP shall be observed by the permittee with a frequency of not less than once per day. The permittee shall keep a log of the observations from the packed tower scrubber (PTS-1).
(9 VAC 5-50-140 and 9 VAC-5-80-1180)

53. **Emission Controls** - The exhaust temperature of the emissions leaving the Venturi scrubbers (VS1 and VS2) shall be maintained below 120°F.
(9 VAC 5-50-140 and 9 VAC-5-80-1180)

54. **Monitoring Devices** – Each Venturi scrubber (VS1 and VS2) shall be equipped with a device to continuously measure the scrubber exhaust temperature of the scrubber. Each monitoring device shall be installed, maintained, calibrated and operated in accordance with approved procedures which shall include, as a minimum, the manufacturer's written requirements or recommendations. Each monitoring device shall be provided with adequate access for inspection and shall be in operation when the Venturi scrubbers (VS1 and VS2) are operating.
(9 VAC 5-50-140 and 9 VAC-5-80-1180)

55. **Monitoring Device Observation** - The monitoring devices used to continuously measure the Venturi scrubbers' (VS1 and VS2) exhaust temperature shall be observed by the permittee with a frequency of not less than once per day. The permittee shall keep a log of the observations from the Venturi scrubbers (VS1 and VS2).
(9 VAC 5-50-140 and 9 VAC-5-80-1180)

56. **Air Toxics** – The permittee shall ensure that chlorine dioxide system reagents are mixed and added to the scrubber system as specified by the manufacturer to maintain a chlorine dioxide residual that will control odor without creating excess chlorine emissions. The permittee shall record scrubbing chemical reagent usage on a daily basis and establish a reagent usage ratio that is mathematically related to the stoichiometry of the reagents. The reagent usage ratio shall be maintained in accordance with proper stoichiometric operating ranges as specified by the manufacturer. The permittee shall make available to DEQ documentation from the manufacturer of appropriate operating ranges and control parameter concentrations.
(9 VAC 5-60-320, 9 VAC 5-50-140 and 9 VAC 5-80-1180)

57. **Odor Controls** – Exterior doors shall be kept closed at all times unless some activity prevents them from being closed, for example, the unloading of trucks, trailers, equipment or material being moved in or out.
(9 VAC 5-50-140 and 9 VAC 5-80-1180)

58. **Odor Controls** – The permittee shall not cause or permit any odorous emissions to be discharged into the atmosphere from the permittee's property which causes an odor objectionable to individuals of ordinary sensibility.
(9 VAC 5-50-140 and 9 VAC 5-80-1180)

59. **Odor Control** – In the event DEQ investigates and determines that excessive odor exists, DEQ may require that the raw materials no longer be fed to the process causing the odor. The remaining raw materials for this process and any incoming raw material shall be diverted to another plant site until the problem is corrected.
(9 VAC 5-50-140 and 9 VAC 5-80-1180)

60. **Emission Limits** – Total emissions from the scrubber controlling the rendering process (PTS-1) shall not exceed the limits specified below:

Chlorine	0.09 lbs/hr	0.21 tons/yr

(9 VAC 5 80-1180 and 9 VAC 5-60-320)

RECEIVING, UNLOADING AND LOADOUT REQUIREMENTS

61. **Odor Control** – The permittee shall unload and process all raw material in a timely manner upon arrival at the facility.
(9 VAC 5-50-140 and 9 VAC 5-80-1180)

62. **Odor Control** – With the exception of trucks containing street-tonnage, vehicles used for hauling incoming raw materials:

    a. Shall be constructed and operated so as to prevent spillage, and covered to prevent exposure to odor carrying air currents.

    b. Vehicles, upon being unloaded, shall be promptly washed and deodorized prior to being parked or put back on the road.

    c. There shall be no more than one uncovered vehicle in transit between the unloading area and the scales at any given time.

    d. In those instances where uncovered, partially unloaded vehicles are parked outside the plant enclosure prior to complete unloading, the trucks shall be covered within 15 minutes of parking.

    e. A record shall be kept which identifies each vehicle and records the arrival and unloading time of each truck. These records shall be available for inspection.

(9 VAC 5-50-140 and 9 VAC 5-80-1180)

HAUL ROADS/PARKING LOTS

63. **Odor Control** – Unloading and outloading areas outside the buildings shall be paved with a non-porous material to avoid malodorous contamination.
(9 VAC 5-50-140 and 9 VAC 5-80-1180)

64. **Odor Control** – All spilled raw or processed material, whether solid or liquid, shall be cleaned up immediately.
(9 VAC 5-50-140 and 9 VAC 5-80-1180)

MONITORING AND RECORDKEEPING

65. **Monitoring Device** – The permittee shall install and maintain odor detection (sniff) tubes in the packed tower scrubber (Ref. PTS-1) exhaust stack that are vented near ground level so that samples of the scrubber exhaust may be evaluated by olfactory means. The permittee shall monitor the sniff tubes for odor at least once per eight-hour shift. If rendering or chemical odors are detected from the sniff tubes, the scrubber operation shall be adjusted in accordance with the DEQ approved malfunction abatement plan. The permittee shall keep a log of sniff tube observations including any adjustments made as a result of the observation.
(9 VAC 5-60-320, 9 VAC 5-50-140 and 9 VAC 5-80-1180)

66. **Odor Complaints** – The permittee shall keep a log of odor complaints received and action(s) taken. This log shall be available for inspection by any State or County Official. The Director, Valley Regional Office, shall be notified by the close of business on the next full business day following the receipt of any complaint. In addition, the owner shall provide within 14 days, copies of each individual odor response form explaining the results of the odor investigation and corrective actions taken.
(9 VAC 5-50-140 and 9 VAC 5-80-1180)

67. **Malfunction Abatement Plan** - The permittee shall submit a malfunction abatement plan to minimize the duration and frequency of malfunctions, which may result in emissions of odors objectionable to individuals of ordinary sensibility. The plan shall be submitted in writing for approval by the Director, Valley Regional Office, within 90 days of permit issuance, and shall specify all of the following:

    a. A complete preventative maintenance program, including identification of the supervisory personnel responsible for overseeing the inspection, maintenance, and repair of air-cleaning devices, a description of the items or condition that shall be inspected, the frequency of these inspections or repairs, and an identification of the major replacement parts that shall be maintained in inventory for quick replacement.

b. An identification of the source and air-cleaning device operating variables that shall be monitored to detect a malfunction, the normal operating range of these variables, and a description of the method of monitoring or surveillance procedures.

c. A description of the corrective procedures or operational changes that shall be taken in the event of a malfunction or failure to achieve compliance with the applicable emission limits..

The permittee shall operate in accordance with the approved malfunction abatement plan. Any changes made to the malfunction abatement plan shall be submitted for approval by the Director, Valley Regional Office, within 30 days of the change. The permittee shall review the malfunction abatement plan annually to insure that the plan can be practically implemented under normal operating conditions. The results of this review shall be submitted to the Director, Valley Regional Office, by March 1 of each year.
(9 VAC 5-50-140 and 9 VAC 5-80-1180)

68. **Odor Control Records** – The permittee shall maintain records of odor control parameters as necessary to demonstrate compliance with this State Only Enforceable section of the permit. The content and format of such records shall be arranged with the Director, Valley Regional Office. These records shall include but are not limited to the following:

a. A log of daily monitoring device observations as required by Conditions 52 and 55 to include the ORP readings on the packed tower scrubber (Ref. PTS-1) and the exhaust gas temperature from the Venturi scrubbers (VS1 and VS2).

b. Log of all spills and clean up action(s) taken required by Condition 64 of this permit.

c. DEQ approved Malfunction Abatement Plan as required by Condition 67 of this permit.

d. Record of truck arrival and unloading times.

e. Daily usage (in pounds) of chlorine gas and sodium chlorite and/or ZA300 HS; daily ratio of chlorine gas to sodium chlorite, if applicable; and sniff tube observations.

f. Odor complaint records.

These records shall be available for inspection by the DEQ and shall be current for the most recent five years.
(9 VAC 5-50-140 and 9 VAC 5-80-1180)

SOURCE TESTING REPORT FORMAT

Cover
1. Plant name and location
2. Units tested at source (indicate Ref. No. used by source in permit or registration)
3. Tester; name, address and report date

Certification
1. Signed by team leader / certified observer (include certification date)
* 2. Signed by reviewer

Introduction
1. Test purpose
2. Test location, type of process
3. Test dates
* 4. Pollutants tested
5. Test methods used
6. Observers' names (industry and agency)
7. Any other important background information

Summary of Results
1. Pollutant emission results / visible emissions summary
2. Input during test vs. rated capacity
3. Allowable emissions
* 4. Description of collected samples, to include audits when applicable
5. Discussion of errors, both real and apparent

Source Operation
1. Description of process and control devices
2. Process and control equipment flow diagram
3. Process and control equipment data

* Sampling and Analysis Procedures
1. Sampling port location and dimensioned cross section
2. Sampling point description
3. Sampling train description
4. Brief description of sampling procedures with discussion of deviations from standard methods
5. Brief description of analytical procedures with discussion of deviation from standard methods

Appendix
* 1. Process data and emission results example calculations
2. Raw field data
* 3. Laboratory reports
4. Raw production data
* 5. Calibration procedures and results
6. Project participants and titles
7. Related correspondence
8. Standard procedures

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* Not applicable to visible emission evaluations.

OPACITY MONITORING REPORT FORMAT

Opacity Continuous Emissions Monitoring System (CEMS) Performance

Date of Last Audit _______________ Results ______________________
Date of Next Scheduled Audit ____________________

Opacity CEMS Performance

Causes of CEMS Downtime	Total Downtime (hours)	% Unavailable (1)	Comment
Monitor Equipment Malfunctions		%	
Non-monitor CEMS Equipment Malfunctions (e.g. computer, data recorder, etc.)		%	
Calibration Q/A		%	
Other Known Causes		%	
Unknown Causes		%	
Total		%	

(1) "% Unavailable" is calculated by the following equations:

CEMS Downtime (2) During Boiler Operating Time (hours)/ Boiler Operating Time (hours) x 100 = % Unavailable

Where:

Time in Semi-annual period (hours) – Boiler Downtime (hours) = Boiler Operating Time (hours)

Opacity Emissions Performance

Note: Calculate Duration in Hours to the Nearest Tenth; Specify Control Equipment, Process, or Other Problems as Comments

Total Source Operating Time ___________ Hours

Cause of Excess Emissions	Total Duration of EE's (hours)	% Monitored Op. Time (2)	% Op Time in Compliance	Comments
Start-up/Shutdown		%	%	
Control Equipment Problems		%	%	
Process Problems		%	%	
Other Known Problems		%	%	
Total		%	%	

(2) "% Monitored Op. Time" is calculated by the following equation:

Total Duration of Excess Emissions (hours) / Monitored Op. Time (hours) x 100 = % Monitored Op. Time

Where:

Monitored Op. Time (hours) is the total time that both the monitor and boiler have been operating during the semi-annual period.

(ii) The owner or operator of Boiler No. 100 shall keep records of the monitoring required by paragraph (b)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner of operator of Boiler No. 100 shall perform all the applicable reporting and recordkeeping requirements of § 60.49b.

(u) *Site-specific standard for Merck & Co., Inc.'s Stonewall Plant in Elkton, Virginia.* (1) This paragraph applies only to the pharmaceutical manufacturing facility, commonly referred to as the Stonewall Plant, located at Route 340 South, in Elkton, Virginia ("site") and only to the natural gas-fired boilers installed as part of the powerhouse conversion required pursuant to 40 CFR 52.2454(g). The requirements of this paragraph shall apply, and the requirements of §§ 60.40b through 60.49b(t) shall not apply, to the natural gas-fired boilers installed pursuant to 40 CFR 52.2454(g).

(i) The site shall equip the natural gas-fired boilers with low nitrogen oxide (NO_X) technology.

(ii) The site shall install, calibrate, maintain, and operate a continuous monitoring and recording system for measuring NO_X emissions discharged to the atmosphere and opacity using a continuous emissions monitoring system or a predictive emissions monitoring system.

(iii) Within 180 days of the completion of the powerhouse conversion, as required by 40 CFR 52.2454, the site shall perform a stack test to quantify criteria pollutant emissions.

(2) [Reserved]

(v) The owner or operator of an affected facility may submit electronic quarterly reports for SO_2 and/or NO_X and/or opacity in lieu of submitting the written reports required under paragraphs (h), (i), (j), (k) or (l) of this section. The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period. Before submitting reports in the electronic format, the owner or operator shall coordinate with the permitting authority to obtain their agreement to submit reports in this alternative format.

(w) The reporting period for the reports required under this subpart is each 6 month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

[52 FR 47842, Dec. 16, 1987, as amended at 54 FR 51820, 51825, Dec. 18, 1989; 60 FR 28062, May 30, 1995; 61 FR 14031, Mar. 29, 1996; 62 FR 52641, Oct. 8, 1997; 63 FR 49455, Sept. 16, 1998; 64 FR 7464, Feb. 12, 1999; 65 FR 13243, Mar. 13, 2000]

Subpart Dc—Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

SOURCE: 55 FR 37683, Sept. 12, 1990, unless otherwise noted.

§ 60.40c Applicability and delegation of authority.

(a) Except as provided in paragraph (d) of this section, the affected facility to which this subpart applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million Btu per hour (Btu/hr)) or less, but greater than or equal to 2.9 MW (10 million Btu/hr).

(b) In delegating implementation and enforcement authority to a State under section 111(c) of the Clean Air Act, § 60.48c(a)(4) shall be retained by the Administrator and not transferred to a State.

(c) Steam generating units which meet the applicability requirements in paragraph (a) of this section are not subject to the sulfur dioxide (SO_2) or particulate matter (PM) emission limits, performance testing requirements, or monitoring requirements under this subpart (§§ 60.42c, 60.43c, 60.44c, 60.45c, 60.46c, or 60.47c) during periods of combustion research, as defined in § 60.41c.

(d) Any temporary change to an existing steam generating unit for the purpose of conducting combustion research is not considered a modification under § 60.14.

[55 FR 37683, Sept. 12, 1990, as amended at 61 FR 20736, May 8, 1996]

§ 60.41c Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act and in subpart A of this part.

Annual capacity factor means the ratio between the actual heat input to a steam generating unit from an individual fuel or combination of fuels during a period of 12 consecutive calendar months and the potential heat input to the steam generating unit from all fuels had the steam ch a separate source (such as a stationary gas turbine, internal combustion engine, or kiln) provides exhaust gas to a steam generating unit.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society for Testing and Materials in ASTM D388-77, "Standard Specification for Classification of Coals by Rank" (incorporated by reference—see § 60.17); coal refuse; and petroleum coke. Synthetic fuels derived from coal for the purpose of creating useful heat, including but not limited to solvent-refined coal, gasified coal, coal-oil mixtures, and coal-water mixtures, are included in this definition for the purposes of this subpart.

Coal refuse means any by-product of coal mining or coal cleaning operations with an ash content greater than 50 percent (by weight) and a heating value less than 13,900 kilojoules per kilogram (kJ/kg) (6,000 Btu per pound (Btu/lb) on a dry basis.

Cogeneration steam generating unit means a steam generating unit that simultaneously produces both electrical (or mechanical) and thermal energy from the same primary energy source.

Combined cycle system means a system in which a separate source (such as a stationary gas turbine, internal combustion engine, or kiln) provides exhaust gas to a steam generating unit.

Combustion research means the experimental firing of any fuel or combination of fuels in a steam generating unit for the purpose of conducting research and development of more efficient combustion or more effective prevention or control of air pollutant emissions from combustion, provided that, during these periods of research and development, the heat generated is not used for any purpose other than preheating combustion air for use by that steam generating unit (i.e., the heat generated is released to the atmosphere without being used for space heating, process heating, driving pumps, preheating combustion air for other units, generating electricity, or any other purpose).

Conventional technology means wet flue gas desulfurization technology, dry flue gas desulfurization technology, atmospheric fluidized bed combustion technology, and oil hydrodesulfurization technology.

Distillate oil means fuel oil that complies with the specifications for fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D396-78, 89, 90, 92, 96, or 98, "Standard Specification for Fuel Oils" (incorporated by reference—see § 60.17).

Dry flue gas desulfurization technology means a sulfur dioxide (SO_2) control system that is located between the steam generating unit and the exhaust vent or stack, and that removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a dry powder material. This definition includes devices where the dry powder material is subsequently converted to another form. Alkaline reagents used in dry flue gas desulfurization systems include, but are not limited to, lime and sodium compounds.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source (such as a stationary gas turbine, internal combustion engine, kiln, etc.) to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a steam generating unit.

Emerging technology means any SO_2 control system that is not defined as a conventional technology under this section, and for which the owner or operator of the affected facility has received approval from the Administrator to operate as an emerging technology under § 60.48c(a)(4).

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR Parts 60 and 61, requirements within any applicable State implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 40 CFR 51.24.

Fluidized bed combustion technology means a device wherein fuel is distributed onto a bed (or series of beds) of limestone aggregate (or other sorbent materials) for combustion; and these materials are forced upward in the device by the flow of combustion air and the gaseous products of combustion. Fluidized bed combustion technology includes, but is not limited to, bubbling bed units and circulating bed units.

Fuel pretreatment means a process that removes a portion of the sulfur in a fuel before combustion of the fuel in a steam generating unit.

Heat input means heat derived from combustion of fuel in a steam generating unit and does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust gases from other sources (such as stationary gas turbines, internal combustion engines, and kilns).

Heat transfer medium means any material that is used to transfer heat from one point to another point.

Maximum design heat input capacity means the ability of a steam generating unit to combust a stated maximum amount of fuel (or combination of fuels) on a steady state basis as determined by the physical design and characteristics of the steam generating unit.

Natural gas means (1) a naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane, or (2) liquefied petroleum (LP) gas, as defined by the American Society for Testing and Materials in ASTM D1835-86, 87, 91, or 97, "Standard Specification for Liquefied Petroleum Gases" (incorporated by reference—see § 60.17).

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Oil means crude oil or petroleum, or a liquid fuel derived from crude oil or petroleum, including distillate oil and residual oil.

Potential sulfur dioxide emission rate means the theoretical SO_2 emissions (nanograms per joule [ng/J], or pounds per million Btu [lb/million Btu] heat input) that would result from combusting fuel in an uncleaned state and without using emission control systems.

Process heater means a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst.

Residual oil means crude oil, fuel oil that does not comply with the specifications under the definition of distillate oil, and all fuel oil numbers 4, 5, and 6, as defined by the American Society for Testing and Materials in ASTM D396-78, 89, 90, 92, 96, or 98, "Standard Specification for Fuel Oils" (incorporated by reference—see § 60.17).

Steam generating unit means a device that combusts any fuel and produces steam or heats water or any other heat transfer medium. This term includes any duct burner that combusts fuel and is part of a combined cycle system. This term does not include process heaters as defined in this subpart.

Steam generating unit operating day means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

Wet flue gas desulfurization technology means an SO_2 control system that is located between the steam generating unit and the exhaust vent or stack, and that removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a liquid material. This definition includes devices where the liquid material is subsequently converted to another form. Alkaline reagents used in wet flue gas desulfurization systems include, but are not limited to, lime, limestone, and sodium compounds.

Wet scrubber system means any emission control device that mixes an aqueous stream or slurry with the exhaust gases from a steam generating unit to control emissions of particulate matter (PM) or SO_2.

Wood means wood, wood residue, bark, or any derivative fuel or residue thereof, in any form, including but not limited to sawdust, sanderdust, wood chips, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest residues.

[55 FR 37683, Sept. 12, 1990, as amended at 61 FR 20736, May 8, 1996; 65 FR 61752, Oct. 17, 2000]

§ 60.42c Standard for sulfur dioxide.

(a) Except as provided in paragraphs (b), (c), and (e) of this section, on and after the date on which the initial performance test is completed or required to be completed under § 60.8 of this part, whichever date comes first, the owner or operator of an affected facility that combusts only coal shall neither: (1) cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of 10 percent (0.10) of the potential SO_2 emission rate (90 percent reduction); nor (2) cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of 520 ng/J (1.2 lb/million Btu) heat input. If coal is combusted with other fuels, the affected facility is subject to the 90 percent SO_2 reduction requirement specified in this paragraph and the emission limit is determined pursuant to paragraph (e)(2) of this section.

(b) Except as provided in paragraphs (c) and (e) of this section, on and after the date on which the initial performance test is completed or required to be completed under § 60.8 of this part, whichever date comes first, the owner or operator of an affected facility that:

(1) Combusts coal refuse alone in a fluidized bed combustion steam generating unit shall neither:

(i) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of 20 percent (0.20) of the potential SO_2 emission rate (80 percent reduction); nor

(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of 520 ng/J (1.2 lb/million Btu) heat input. If coal is fired with coal refuse, the affected facility is subject to paragraph (a) of this section. If oil or any other fuel (except coal) is fired with coal refuse, the affected facility is subject to the 90 percent SO_2 reduction requirement specified in paragraph (a) of this section and the emission limit determined pursuant to paragraph (e)(2) of this section.

(2) Combusts only coal and that uses an emerging technology for the control of SO_2 emissions shall neither:

(i) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of 50 percent (0.50) of the potential SO_2 emission rate (50 percent reduction); nor

(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of 260 ng/J (0.60 lb/million Btu) heat input. If coal is combusted with other fuels, the affected facility is subject to the 50 percent SO_2 reduction requirement specified in this paragraph and the emission limit determined pursuant to paragraph (e)(2) of this section.

(c) On and after the date on which the initial performance test is completed or required to be completed under § 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts coal, alone or in combination with any other fuel, and is listed in paragraphs (c)(1), (2), (3), or (4) of this section shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of the emission limit determined pursuant to paragraph (e)(2) of this section. Percent reduction requirements are not applicable to affected facilities under paragraphs (c)(1), (2), (3), or (4).

(1) Affected facilities that have a heat input capacity of 22 MW (75 million Btu/hr) or less.

(2) Affected facilities that have an annual capacity for coal of 55 percent

(0.55) or less and are subject to a Federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for coal of 55 percent (0.55) or less.

(3) Affected facilities located in a noncontinental area.

(4) Affected facilities that combust coal in a duct burner as part of a combined cycle system where 30 percent (0.30) or less of the heat entering the steam generating unit is from combustion of coal in the duct burner and 70 percent (0.70) or more of the heat entering the steam generating unit is from exhaust gases entering the duct burner.

(d) On and after the date on which the initial performance test is completed or required to be completed under § 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts oil shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of 215 ng/J (0.50 lb/million Btu) heat input; or, as an alternative, no owner or operator of an affected facility that combusts oil shall combust oil in the affected facility that contains greater than 0.5 weight percent sulfur. The percent reduction requirements are not applicable to affected facilities under this paragraph.

(e) On and after the date on which the initial performance test is completed or required to be completed under § 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts coal, oil, or coal and oil with any other fuel shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of the following:

(1) The percent of potential SO_2 emission rate required under paragraph (a) or (b)(2) of this section, as applicable, for any affected facility that

(i) Combusts coal in combination with any other fuel,

(ii) Has a heat input capacity greater than 22 MW (75 million Btu/hr), and

(iii) Has an annual capacity factor for coal greater than 55 percent (0.55); and

(2) The emission limit determined according to the following formula for any affected facility that combusts coal, oil, or coal and oil with any other fuel:

$$E_s=(K_a H_a+K_b H_b+K_c H_c)/H_a+H_b+H_c)$$

where:

E_s is the SO_2 emission limit, expressed in ng/J or lb/million Btu heat input,
K_a is 520 ng/J (1.2 lb/million Btu).
K_b is 260 ng/J (0.60 lb/million Btu).
K_c is 215 ng/J (0.50 lb/million Btu).
H_a is the heat input from the combustion of coal, except coal combusted in an affected facility subject to paragraph (b)(2) of this section, in Joules (J) [million Btu]
H_b is the heat input from the combustion of coal in an affected facility subject to paragraph (b)(2) of this section, in J (million Btu)
H_c is the heat input from the combustion of oil, in J (million Btu).

(f) Reduction in the potential SO_2 emission rate through fuel pretreatment is not credited toward the percent reduction requirement under paragraph (b)(2) of this section unless:

(1) Fuel pretreatment results in a 50 percent (0.50) or greater reduction in the potential SO_2 emission rate; and

(2) Emissions from the pretreated fuel (without either combustion or post-combustion SO_2 control) are equal to or less than the emission limits specified under paragraph (b)(2) of this section.

(g) Except as provided in paragraph (h) of this section, compliance with the percent reduction requirements, fuel oil sulfur limits, and emission limits of this section shall be determined on a 30-day rolling average basis.

(h) For affected facilities listed under paragraphs (h)(1), (2), or (3) of this section, compliance with the emission limits or fuel oil sulfur limits under this section may be determined based on a certification from the fuel supplier, as described under § 60.48c(f)(1), (2), or (3), as applicable.

(1) Distillate oil-fired affected facilities with heat input capacities between 2.9 and 29 MW (10 and 100 million Btu/hr).

(2) Residual oil-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 million Btu/hr).

(3) Coal-fired facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 million Btu/hr).

(i) The SO_2 emission limits, fuel oil sulfur limits, and percent reduction requirements under this section apply at all times, including periods of startup, shutdown, and malfunction.

(j) Only the heat input supplied to the affected facility from the combustion of coal and oil is counted under this section. No credit is provided for the heat input to the affected facility from wood or other fuels or for heat derived from exhaust gases from other sources, such as stationary gas turbines, internal combustion engines, and kilns.

[55 FR 37683, Sept. 12, 1990, as amended at 65 FR 61753, Oct. 17, 2000]

§ 60.43c Standard for particulate matter.

(a) On and after the date on which the initial performance test is completed or required to be completed under § 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts coal or combusts mixtures of coal with other fuels and has a heat input capacity of 8.7 MW (30 million Btu/hr) or greater, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emission limits:

(1) 22 ng/J (0.051 lb/million Btu) heat input if the affected facility combusts only coal, or combusts coal with other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.

(2) 43 ng/J (0.10 lb/million Btu) heat imput if the affected facility combusts coal with other fuels, has an annual capacity factor for the other fuels greater than 10 percent (0.10), and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor greater than 10 percent (0.10) for fuels other than coal.

(b) On and after the date on which the initial performance test is completed or required to be completed under § 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts wood or combusts mixtures of wood with other fuels (except coal) and has a heat input capacity of 8.7 MW (30 million Btu/hr) or greater, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emissions limits:

(1) 43 ng/J (0.10 lb/million Btu) heat input if the affected facility has an annual capacity factor for wood greater than 30 percent (0.30); or

(2) 130 ng/J (0.30 lb/million Btu) heat input if the affected facility has an annual capacity factor for wood of 30 percent (0.30) or less and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for wood of 30 percent (0.30) or less.

(c) On and after the date on which the initial performance test is completed or required to be completed under § 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts coal, wood, or oil and has a heat input capacity of 8.7 MW (30 million Btu/hr) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

(d) The PM and opacity standards under this section apply at all times, except during periods of startup, shutdown, or malfunction.

[55 FR 37683, Sept. 12, 1990, as amended at 65 FR 61753, Oct. 17, 2000]

§ 60.44c Compliance and performance test methods and procedures for sulfur dioxide.

(a) Except as provided in paragraphs (g) and (h) of this section and in § 60.8(b), performance tests required under § 60.8 shall be conducted following the procedures specified in paragraphs (b), (c), (d), (e), and (f) of this section, as applicable. Section 60.8(f) does not apply to this section. The 30-day notice required in § 60.8(d) applies only to the initial performance test unless otherwise specified by the Administrator.

(b) The initial performance test required under § 60.8 shall be conducted over 30 consecutive operating days of the steam generating unit. Compliance with the percent reduction requirements and SO_2 emission limits under

§ 60.42c shall be determined using a 30-day average. The first operating day included in the initial performance test shall be scheduled within 30 days after achieving the maximum production rate at which the affect facility will be operated, but not later than 180 days after the initial startup of the facility. The steam generating unit load during the 30-day period does not have to be the maximum design heat input capacity, but must be representative of future operating conditions.

(c) After the initial performance test required under paragraph (b) and § 60.8, compliance with the percent reduction requirements and SO_2 emission limits under § 60.42c is based on the average percent reduction and the average SO_2 emission rates for 30 consecutive steam generating unit operating days. A separate performance test is completed at the end of each steam generating unit operating day, and a new 30-day average percent reduction and SO_2 emission rate are calculated to show compliance with the standard.

(d) If only coal, only oil, or a mixture of coal and oil is combusted in an affected facility, the procedures in Method 19 are used to determine the hourly SO_2 emission rate (E_{ho}) and the 30-day average SO_2 emission rate (E_{ao}). The hourly averages used to compute the 30-day averages are obtained from the continuous emission monitoring system (CEMS). Method 19 shall be used to calculate E_{ao} when using daily fuel sampling or Method 6B.

(e) If coal, oil, or coal and oil are combusted with other fuels:

(1) An adjusted E_{ho} ($E_{ho}o$) is used in Equation 19-19 of Method 19 to compute the adjusted E_{ao} ($E_{ao}o$). The $E_{ho}o$ is computed using the following formula:

$$E_{ho}o=[E_{ho}-E_w(1-X_k)]/X_k$$

where:

$E_{ho}o$ is the adjusted E_{ho}, ng/J (lb/million Btu)

E_{ho} is the hourly SO_2 emission rate, ng/J (lb/million Btu)

E_w is the SO_2 concentration in fuels other than coal and oil combusted in the affected facility, as determined by fuel sampling and analysis procedures in Method 9, ng/J (lb/million Btu). The value E_w for each fuel lot is used for each hourly average during the time that the lot is being combusted. The owner or operator does not have to measure E_w if the owner or operator elects to assume $E_w=0$.

X_k is the fraction of the total heat input from fuel combustion derived from coal and oil, as determined by applicable procedures in Method 19.

(2) The owner or operator of an affected facility that qualifies under the provisions of § 60.42c(c) or (d) [where percent reduction is not required] does not have to measure the parameters E_w or X_k if the owner or operator of the affected facility elects to measure emission rates of the coal or oil using the fuel sampling and analysis procedures under Method 19.

(f) Affected facilities subject to the percent reduction requirements under § 60.42c(a) or (b) shall determine compliance with the SO_2 emission limits under § 60.42c pursuant to paragraphs (d) or (e) of this section, and shall determine compliance with the percent reduction requirements using the following procedures:

(1) If only coal is combusted, the percent of potential SO_2 emission rate is computed using the following formula:

$$\%P_s=100(1-\%R_g/100)(1-\%R_f/100)$$

where

$\%P_s$ is the percent of potential SO_2 emission rate, in percent

$\%R_g$ is the SO_2 removal efficiency of the control device as determined by Method 19, in percent

$\%R_f$ is the SO_2 removal efficiency of fuel pretreatment as determined by Method 19, in percent

(2) If coal, oil, or coal and oil are combusted with other fuels, the same procedures required in paragraph (f)(1) of this section are used, except as provided for in the following:

(i) To compute the $\%P_s$, an adjusted $\%R_g$ ($\%R_go$) is computed from $E_{ao}o$ from paragraph (e)(1) of this section and an adjusted average SO_2 inlet rate ($E_{ai}o$) using the following formula:

$$\%R_go=100\ [1.0-E_{ao}o/E_{ai}o)]$$

where:

$\%R_go$ is the adjusted $\%R_g$, in percent

$E_{ao}o$ is the adjusted E_{ao}, ng/J (lb/million Btu)

$E_{ai}o$ is the adjusted average SO_2 inlet rate, ng/J (lb/million Btu)

(ii) To compute $E_{ai}o$, an adjusted hourly SO_2 inlet rate ($E_{hi}o$) is used. The

$E_{hi}o$ is computed using the following formula:

$$E_{hi}o=[E_{hi}-E_w\,(1-X_k)]/X_k$$

where:

$E_{hi}o$ is the adjusted E_{hi}, ng/J (lb/million Btu)
E_{hi} is the hourly SO_2 inlet rate, ng/J (lb/million Btu)
E_w is the SO_2 concentration in fuels other than coal and oil combusted in the affected facility, as determined by fuel sampling and analysis procedures in Method 19, ng/J (lb/million Btu). The value E_w for each fuel lot is used for each hourly average during the time that the lot is being combusted. The owner or operator does not have to measure E_w if the owner or operator elects to assume $E_w = 0$.
X_k is the fraction of the total heat input from fuel combustion derived from coal and oil, as determined by applicable procedures in Method 19.

(g) For oil-fired affected facilities where the owner or operator seeks to demonstrate compliance with the fuel oil sulfur limits under §60.42c based on shipment fuel sampling, the initial performance test shall consist of sampling and analyzing the oil in the initial tank of oil to be fired in the steam generating unit to demonstrate that the oil contains 0.5 weight percent sulfur or less. Thereafter, the owner or operator of the affected facility shall sample the oil in the fuel tank after each new shipment of oil is received, as described under §60.46c(d)(2).

(h) For affected facilities subject to §60.42c(h)(1), (2), or (3) where the owner or operator seeks to demonstrate compliance with the SO_2 standards based on fuel supplier certification, the performance test shall consist of the certification, the certification from the fuel supplier, as described under §60.48c(f)(1), (2), or (3), as applicable.

(i) The owner or operator of an affected facility seeking to demonstrate compliance with the SO_2 standards under §60.42c(c)(2) shall demonstrate the maximum design heat input capacity of the steam generating unit by operating the steam generating unit at this capacity for 24 hours. This demonstration shall be made during the initial performance test, and a subsequent demonstration may be requested at any other time. If the demonstrated 24-hour average firing rate for the affected facility is less than the maximum design heat input capacity stated by the manufacturer of the affected facility, the demonstrated 24-hour average firing rate shall be used to determine the annual capacity factor for the affected facility; otherwise, the maximum design heat input capacity provided by the manufacturer shall be used.

(j) The owner or operator of an affected facility shall use all valid SO_2 emissions data in calculating $\%P_s$ and E_{ho} under paragraphs (d), (e), or (f) of this section, as applicable, whether or not the minimum emissions data requirements under §60.46c(f) are achieved. All valid emissions data, including valid data collected during periods of startup, shutdown, and malfunction, shall be used in calculating $\%P_s$ or E_{ho} pursuant to paragraphs (d), (e), or (f) of this section, as applicable.

[55 FR 37683, Sept. 12, 1990, as amended at 65 FR 61753, Oct. 17, 2000]

§60.45c Compliance and performance test methods and procedures for particulate matter.

(a) The owner or operator of an affected facility subject to the PM and/or opacity standards under §60.43c shall conduct an initial performance test as required under §60.8, and shall conduct subsequent performance tests as requested by the Administrator, to determine compliance with the standards using the following procedures and reference methods.

(1) Method 1 shall be used to select the sampling site and the number of traverse sampling points.

(2) Method 3 shall be used for gas analysis when applying Method 5, Method 5B, or Method 17.

(3) Method 5, Method 5B, or Method 17 shall be used to measure the concentration of PM as follows:

(i) Method 5 may be used only at affected facilities without wet scrubber systems.

(ii) Method 17 may be used at affected facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a temperature of 160 °C (320 °F). The procedures of Sections 8.1 and 11.1 of Method 5B may be used in Method 17 only if Method 17 is used in conjunction with a wet scrubber system. Method 17 shall not be used in conjunction with a wet scrubber system if the effluent is saturated or laden with water droplets.

(iii) Method 5B may be used in conjunction with a wet scrubber system.

(4) The sampling time for each run shall be at least 120 minutes and the minimum sampling volume shall be 1.7 dry standard cubic meters (dscm) [60 dry standard cubic feet (dscf)] except that smaller sampling times or volumes may be approved by the Administrator when necessitated by process variables or other factors.

(5) For Method 5 or Method 5B, the temperature of the sample gas in the probe and filter holder shall be monitored and maintained at 160±14 °C (320±25 °F).

(6) For determination of PM emissions, an oxygen or carbon dioxide measurement shall be obtained simultaneously with each run of Method 5, Method 5B, or Method 17 by traversing the duct at the same sampling location.

(7) For each run using Method 5, Method 5B, or Method 17, the emission rates expressed in ng/J (lb/million Btu) heat input shall be determined using:

(i) The oxygen or carbon dioxide measurements and PM measurements obtained under this section,

(ii) The dry basis F-factor, and

(iii) The dry basis emission rate calculation procedure contained in Method 19 (appendix A).

(8) Method 9 (6-minute average of 24 observations) shall be used for determining the opacity of stack emissions.

(b) The owner or operator of an affected facility seeking to demonstrate compliance with the PM standards under § 60.43c(b)(2) shall demonstrate the maximum design heat input capacity of the steam generating unit by operating the steam generating unit at this capacity for 24 hours. This demonstration shall be made during the initial performance test, and a subsequent demonstration may be requested at any other time. If the demonstrated 24-hour average firing rate for the affected facility is less than the maximum design heat input capacity stated by the manufacturer of the affected facility, the demonstrated 24-hour average firing rate shall be used to determine the annual capacity factor for the affected facility; otherwise, the maximum design heat input capacity provided by the manufacturer shall be used.

[55 FR 37683, Sept. 12, 1990, as amended at 65 FR 61753, Oct. 17, 2000]

§ 60.46c Emission monitoring for sulfur dioxide

(a) Except as provided in paragraphs (d) and (e) of this section, the owner or operator of an affected facility subject to the SO_2 emission limits under § 60.42c shall install, calibrate, maintain, and operate a CEMS for measuring SO_2 concentrations and either oxygen or carbon dioxide concentrations at the outlet of the SO_2 control device (or the outlet of the steam generating unit if no SO_2 control device is used), and shall record the output of the system. The owner or operator of an affected facility subject to the percent reduction requirements under § 60.42c shall measure SO_2 concentrations and either oxygen or carbon dioxide concentrations at both the inlet and outlet of the SO_2 control device.

(b) The 1-hour average SO_2 emission rates measured by a CEMS shall be expressed in ng/J or lb/million Btu heat input and shall be used to calculate the average emission rates under § 60.42c. Each 1-hour average SO_2 emission rate must be based on at least 30 minutes of operation and include at least 2 data points representing two 15-minute periods. Hourly SO_2 emission rates are not calculated if the affected facility is operated less than 30 minutes in a 1-hour period and are not counted toward determination of a steam generating unit operating day.

(c) The procedures under § 60.13 shall be followed for installation, evaluation, and operation of the CEMS.

(1) All CEMS shall be operated in accordance with the applicable procedures under Performance Specifications 1, 2, and 3 (appendix B).

(2) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with Procedure 1 (appendix F).

(3) For affected facilities subject to the percent reduction requirements under § 60.42c, the span value of the SO_2 CEMS at the inlet to the SO_2 control device shall be 125 percent of the maximum estimated hourly potential SO_2

emission rate of the fuel combusted, and the span value of the SO_2 CEMS at the outlet from the SO_2 control device shall be 50 percent of the maximum estimated hourly potential SO_2 emission rate of the fuel combusted.

(4) For affected facilities that are not subject to the percent reduction requirements of §60.42c, the span value of the SO_2 CEMS at the outlet from the SO_2 control device (or outlet of the steam generating unit if no SO_2 control device is used) shall be 125 percent of the maximum estimated hourly potential SO_2 emission rate of the fuel combusted.

(d) As an alternative to operating a CEMS at the inlet to the SO_2 control device (or outlet of the steam generating unit if no SO_2 control device is used) as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO_2 emission rate by sampling the fuel prior to combustion. As an alternative to operating a CEMS at the outlet from the SO_2 control device (or outlet of the steam generating unit if no SO_2 control device is used) as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO_2 emission rate by using Method 6B. Fuel sampling shall be conducted pursuant to either paragraph (d)(1) or (d)(2) of this section. Method 6B shall be conducted pursuant to paragraph (d)(3) of this section.

(1) For affected facilities combusting coal or oil, coal or oil samples shall be collected daily in an as-fired condition at the inlet to the steam generating unit and analyzed for sulfur content and heat content according the Method 19. Method 19 provides procedures for converting these measurements into the format to be used in calculating the average SO_2 input rate.

(2) As an alternative fuel sampling procedure for affected facilities combusting oil, oil samples may be collected from the fuel tank for each steam generating unit immediately after the fule tank is filled and before any oil is combusted. The owner or operator of the affected facility shall analyze the oil sample to determine the sulfur content of the oil. If a partially empty fuel tank is refilled, a new sample and analysis of the fuel in the tank would be required upon filling. Results of the fuel analysis taken after each new shipment of oil is received shall be used as the daily value when calculating the 30-day rolling average until the next shipment is received. If the fuel analysis shows that the sulfur content in the fuel tank is greater than 0.5 weight percent sulfur, the owner or operator shall ensure that the sulfur content of subsequent oil shipments is low enough to cause the 30-day rolling average sulfur content to be 0.5 weight percent sulfur or less.

(3) Method 6B may be used in lieu of CEMS to measure SO_2 at the inlet or outlet of the SO_2 control system. An initial stratification test is required to verify the adequacy of the Method 6B sampling location. The stratification test shall consist of three paired runs of a suitable SO_2 and carbon dioxide measurement train operated at the candidate location and a second similar train operated according to the procedures in §3.2 and the applicable procedures in section 7 of Performance Specification 2 (appendix B). Method 6B, Method 6A, or a combination of Methods 6 and 3 or Methods 6C and 3A are suitable measurement techniques. If Method 6B is used for the second train, sampling time and timer operation may be adjusted for the stratification test as long as an adequate sample volume is collected; however, both sampling trains are to be operated similarly. For the location to be adequate for Method 6B 24-hour tests, the mean of the absolute difference between the three paired runs must be less than 10 percent (0.10).

(e) The monitoring requirements of paragraphs (a) and (d) of this section shall not apply to affected facilities subject to §60.42c(h) (1), (2), or (3) where the owner or operator of the affected facility seeks to demonstrate compliance with the SO_2 standards based on fuel supplier certification, as described under §60.48c(f) (1), (2), or (3), as applicable.

(f) The owner or operator of an affected facility operating a CEMS pursuant to paragraph (a) of this section, or conducting as-fired fuel sampling pursuant to paragraph (d)(1) of this section, shall obtain emission data for at least 75 percent of the operating hours in at least 22 out of 30 successive steam generating unit operating days. If this minimum data requirement is not met with a single monitoring system, the owner or operator of the affected facility shall supplement the emission data with data collected with other monitoring systems as approved by the Administrator.

[55 FR 37683, Sept. 12, 1990, as amended at 65 FR 61753, Oct. 17, 2000]

§ 60.47c Emission monitoring for particulate matter.

(a) The owner or operator of an affected facility combusting coal, residual oil, or wood that is subject to the opacity standards under § 60.43c shall install, calibrate, maintain, and operate a COMS for measuring the opacity of the emissions discharged to the atmosphere and record the output of the system.

(b) All COMS for measuring opacity shall be operated in accordance with the applicable procedures under Performance Specification 1 (appendix B). The span value of the opacity COMS shall be between 60 and 80 percent.

[55 FR 37683, Sept. 12, 1990, as amended at 65 FR 61753, Oct. 17, 2000]

§ 60.48c Reporting and recordkeeping requirements.

(a) The owner or operator of each affected facility shall submit notification of the date of construction or reconstruction, anticipated startup, and actual startup, as provided by § 60.7 of this part. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.

(2) If applicable, a copy of any Federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under § 60.42c, or § 60.43c.

(3) The annual capacity factor at which the owner or operator anticipates operating the affected facility based on all fuels fired and based on each individual fuel fired.

(4) Notification if an emerging technology will be used for controlling SO_2 emissions. The Administrator will examine the description of the control device and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of § 60.42c(a) or (b)(1), unless and until this determination is made by the Administrator.

(b) The owner or operator of each affected facility subject to the SO_2 emission limits of § 60.42c, or the PM or opacity limits of § 60.43c, shall submit to the Administrator the performance test data from the initial and any subsequent performance tests and, if applicable, the performance evaluation of the CEMS and/or COMS using the applicable performance specifications in appendix B.

(c) The owner or operator of each coal-fired, residual oil-fired, or wood-fired affected facility subject to the opacity limits under § 60.43c(c) shall submit excess emission reports for any excess emissions from the affected facility which occur during the reporting period.

(d) The owner or operator of each affected facility subject to the SO_2 emission limits, fuel oil sulfur limits, or percent reduction requirements under § 60.42c shall submit reports to the Administrator.

(e) The owner or operator of each affected facility subject to the SO_2 emission limits, fuel oil sulfur limits, or percent reduction requirements under § 60.43c shall keep records and submit reports as required under paragraph (d) of this section, including the following information, as applicable.

(1) Calendar dates covered in the reporting period.

(2) Each 30-day average SO_2 emission rate (nj/J or lb/million Btu), or 30-day average sulfur content (weight percent), calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission standards; and a description of corrective actions taken.

(3) Each 30-day average percent of potential SO_2 emission rate calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission

standards; and a description of the corrective actions taken.

(4) Identification of any steam generating unit operating days for which SO_2 or diluent (oxygen or carbon dioxide) data have not been obtained by an approved method for at least 75 percent of the operating hours; justification for not obtaining sufficient data; and a description of corrective actions taken.

(5) Identification of any times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and a description of corrective actions taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit.

(6) Identification of the F factor used in calculations, method of determination, and type of fuel combusted.

(7) Identification of whether averages have been obtained based on CEMS rather than manual sampling methods.

(8) If a CEMS is used, identification of any times when the pollutant concentration exceeded the full span of the CEMS.

(9) If a CEMS is used, description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specifications 2 or 3 (appendix B).

(10) If a CEMS is used, results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1.

(11) If fuel supplier certification is used to demonstrate compliance, records of fuel supplier certification is used to demonstrate compliance, records of fuel supplier certification as described under paragraph (f)(1), (2), or (3) of this section, as applicable. In addition to records of fuel supplier certifications, the report shall include a certified statement signed by the owner or operator of the affected facility that the records of fuel supplier certifications submitted represent all of the fuel combusted during the reporting period.

(f) Fuel supplier certification shall include the following information:

(1) For distillate oil:

(i) The name of the oil supplier; and

(ii) A statement from the oil supplier that the oil complies with the specifications under the definition of distillate oil in §60.41c.

(2) For residual oil:

(i) The name of the oil supplier;

(ii) The location of the oil when the sample was drawn for analysis to determine the sulfur content of the oil, specifically including whether the oil was sampled as delivered to the affected facility, or whether the sample was drawn from oil in storage at the oil supplier's or oil refiner's facility, or other location;

(iii) The sulfur content of the oil from which the shipment came (or of the shipment itself); and

(iv) The method used to determine the sulfur content of the oil.

(3) For coal:

(i) The name of the coal supplier;

(ii) The location of the coal when the sample was collected for analysis to determine the properties of the coal, specifically including whether the coal was sampled as delivered to the affected facility or whether the sample was collected from coal in storage at the mine, at a coal preparation plant, at a coal supplier's facility, or at another location. The certification shall include the name of the coal mine (and coal seam), coal storage facility, or coal preparation plant (where the sample was collected);

(iii) The results of the analysis of the coal from which the shipment came (or of the shipment itself) including the sulfur content, moisture content, ash content, and heat content; and

(iv) The methods used to determine the properties of the coal.

(g) The owner or operator of each affected facility shall record and maintain records of the amounts of each fuel combusted during each day.

(h) The owner or operator of each affected facility subject to a Federally enforceable requirement limiting the annual capacity factor for any fuel or mixture of fuels under §60.42c or §60.43c shall calculate the annual capacity factor individually for each fuel combusted. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of the calendar month

(i) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record.

(j) The reporting period for the reports required under this subpart is each six-month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

[55 FR 37683, Sept. 12, 1990, as amended at 64 FR 7465, Feb. 12, 1999; 65 FR 61753, Oct. 17, 2000]

Subpart E—Standards of Performance for Incinerators

§ 60.50 Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to each incinerator of more than 45 metric tons per day charging rate (50 tons/day), which is the affected facility.

(b) Any facility under paragraph (a) of this section that commences construction or modification after August 17, 1971, is subject to the requirements of this subpart.

[42 FR 37936, July 25, 1977]

§ 60.51 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) *Incinerator* means any furnace used in the process of burning solid waste for the purpose of reducing the volume of the waste by removing combustible matter.

(b) *Solid waste* means refuse, more than 50 percent of which is municipal type waste consisting of a mixture of paper, wood, yard wastes, food wastes, plastics, leather, rubber, and other combustibles, and noncombustible materials such as glass and rock.

(c) *Day* means 24 hours.

[36 FR 24877, Dec. 23, 1971, as amended at 39 FR 20792, June 14, 1974]

§ 60.52 Standard for particulate matter.

(a) On and after the date on which the initial performance test is completed or required to be completed under § 60.8 of this part, whichever date comes first, no owner or operator subject to the provisions of this part shall cause to be discharged into the atmosphere from any affected facility any gases which contain particulate matter in excess of 0.18 g/dscm (0.08 gr/dscf) corrected to 12 percent CO_2.

[39 FR 20792, June 14, 1974, as amended at 65 FR 61753, Oct. 17, 2000]

§ 60.53 Monitoring of operations.

(a) The owner or operator of any incinerator subject to the provisions of this part shall record the daily charging rates and hours of operation.

§ 60.54 Test methods and procedures.

(a) In conducting the performance tests required in § 60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in § 60.8(b).

(b) The owner or operator shall determine compliance with the particulate matter standard in § 60.52 as follows:

(1) The concentration (c_{12}) of particulate matter, corrected to 12 percent CO_2, shall be computed for each run using the following equation:

$$c_{12} = c_s\ (12/\%CO_2)$$

where:

c_{12}=concentration of particulate matter, corrected to 12 percent CO_2, g/dscm (gr/dscf).
c_s=concentration of particulate matter, g/dscm (gr/dscf).
$\%CO_2$=CO_2 concentration, percent dry basis.

(2) Method 5 shall be used to determine the particulate matter concentration (c_s). The sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf).

(3) The emission rate correction factor, integrated or grab sampling and analysis procedure of Method 3B shall be used to determine CO_2 concentration ($\%CO_2$).

(i) The CO_2 sample shall be obtained simultaneously with, and at the same traverse points as, the particulate run. If the particulate run has more than 12 traverse points, the CO_2 traverse points may be reduced to 12 if Method 1 is used to locate the 12 CO_2 traverse points. If individual CO_2 samples are taken at each traverse point, the CO_2

ATTACHMENT C

Minor NSR Permit
(dated October 23, 1992)

Patty
E15/CDS
Used 1/13

COMMONWEALTH of VIRGINIA

Department of Air Pollution Control

200-202 NORTH NINTH STREET
NINTH STREET OFFICE BUILDING, EIGHTH FLOOR
P. O. BOX 10089
RICHMOND, VIRGINIA 23240
(804) 786-2378
FAX # (804) 225-3933
TDD # (804) 371-8471

WALLACE N. DAVIS
EXECUTIVE DIRECTOR

October 23, 1992

Mr. Michael A. Smith
Vice President
VALLEY PROTEINS, INC. - LINVILLE DIVISION
P. O. Box 3588
Winchester, VA 22604

Location: Linville, Rockingham Co.
Registration No: 20144
County-Plant No: 2760 - 0023

Dear Mr. Smith:

Attached is a permit to construct and operate a replacement feather dryer in accordance with the provisions of the Commonwealth of Virginia Regulations for the Control and Abatement of Air Pollution.

In the course of evaluating the application and arriving at a final decision to approve the project, the Department of Air Pollution Control (DAPC) deemed the application complete on October 19, 1992.

This approval to construct and operate shall not relieve Valley Proteins, Inc. of the responsibility to comply with all other local, State and Federal permit regulations.

As provided by Rule 2A:2 of the Supreme Court of Virginia, you have 30 days from the date of service of this decision (the date you actually received this decision or the date on which it was mailed to you, whichever occurred first) within which to initiate an appeal for this decision by filing a Notice of Appeal with:

Wallace N. Davis, Director
Department of Air Pollution Control
200-202 North Ninth Street
Ninth Street Office Building, 8th Floor
Richmond, Virginia 23219

In the event that this decision is served on you by mail, three days are added to that period. Please refer to Part Two A of the Rules of the Supreme Court of Virginia for information on the required content of the Notice of Appeal and for additional requirements governing appeals from decisions of administrative agencies.

The permit contains legally enforceable conditions. Failure to comply may result in a Notice of Violation and civil penalty. Please read all permit conditions carefully.

If you have any questions concerning this permit, please call the regional office at (703) 857-7328.

Sincerely,
Donald L. Shepherd

Donald L. Shepherd
Director, Region II

for

Wallace N. Davis
Executive Director

WND/DLS/ROG/bh/Proteins.Per

Attachment: Permit

cc: Director, Division of Technical Evaluation
Director, Division of Data Analysis and Special Studies
Manager, Air Toxics Enforcement and Compliance

COMMONWEALTH of VIRGINIA

Department of Air Pollution Control
200-202 NORTH NINTH STREET
NINTH STREET OFFICE BUILDING, EIGHTH FLOOR
P. O. BOX 10089
RICHMOND, VIRGINIA 23240
(804) 786-2378
FAX # (804) 225-3933
TDD # (804) 371-8471

WALLACE N. DAVIS
EXECUTIVE DIRECTOR

STATIONARY SOURCE PERMIT TO CONSTRUCT AND OPERATE

In compliance with the Federal Clean Air Act and the Commonwealth of Virginia Regulations for the Control and Abatement of Air Pollution,

Valley Proteins, Inc.
P. O. Box 3588
Winchester, VA 22604
Registration No: 20144
County-Plant No: 2760 - 0023

is authorized to construct and operate

a replacement feather dryer

located at

Route 753, one mile
north of Linville, VA

in accordance with the Conditions of this permit.

Approved on October 23, 1992.

Donald L. Shepherd

Donald L. Shepherd
Director, Region II
for
Wallace N. Davis
Executive Director

Permit consists of 7 pages.
Permit Conditions 1 to 20.

PERMIT CONDITIONS - the regulatory reference and authority for each condition is listed in parentheses ( ) after each condition.

1. The permitted facility is to be constructed and operated as represented in the permit application dated October 9, 1992. Any changes in the permit application specifications or any existing facilities which alter the impact of the facility on air quality may require a permit. Failure to obtain such a permit prior to construction may result in enforcement action.
(Section 120-02-11 of State Regulations)

2. Equipment to be constructed consists of:

   - Replace the feather dryer with an equal capacity steamtube dryer.
   - The dryer's rated capacity is 10 tons per hour wet feathers input, 5.4 tons per hour feather meal product output at 10% moisture.

3. Particulate emissions from the replacement feather dryer shall be controlled by a venturi scrubber with a design efficiency of 98%. The scrubber shall be provided with adequate access for inspection. The scrubber shall be equipped with a flow meter and a device to continuously measure the differential pressure through the scrubber.
(Section 120-08-01 F and 120-05-0403 of State Regulations)

4. Odor/VOC emissions from the replacement feather dryer shall be controlled by combusting (afterburning) in the plant's boilers, or approved equivalent, the non-condensible gases from the dryer's air condenser. The boilers shall be provided with adequate access for inspection.
(Section 120-08-01 F and 120-05-0403 of State Regulations)

5. The existing feather dryer shall be replaced with the new feather dryer. Reactivation of this old replaced unit may require a permit.
(Section 120-08-01 of State Regulations)

6. The permitted facility shall be constructed so as to allow for emissions testing and upon reasonable notice at any time, using appropriate methods. Test ports shall be provided at the appropriate locations.
(Section 120-05-03 F of State Regulations)

7. The annual throughput of wet feathers shall not exceed 87,000 tons (47,000 tons of feather meal produced) calculated as the sum of each consecutive 12 month period.
(Section 120-02-11 of State Regulations)

8. Visible emissions from the boilers controlling emissions from the replacement feather dryer shall not exceed 20 percent opacity as determined by EPA Method 9 (reference 40 CFR 60, Appendix A). This condition applies at all times except during startup, shutdown and malfunction.
(Sections 120-02-11 and 120-05-02 of State Regulations)

9. The permittee shall furnish written notification to the Department (Director, Region II) of:

   a. The actual date on which construction of the replacement feather dryer commenced within 10 days after such date.

   b. The actual start-up date of the replacement feather dryer within 10 days after such date.

(Section 120-02-11 of State Regulations)

10. The permittee shall maintain records of all emission data and operating parameters necessary to demonstrate compliance with this permit. The content of and format of such records shall be arranged with the Department (Director, Region II). These records shall include, but are not limited to:

   a. The yearly throughput of wet feather input and feather meal product output, calculated as the sum of each consecutive 12 month period.

These records shall be available for inspection by the Department (Director, Region II) and shall be current for the most recent five (5) years.
(Section 120-05-05 of State Regulations)

11. This permit may be modified or revoked in whole or in part for cause, including, but not limited to, the following:

   a. Violation of any terms or conditions of this permit;

   b. Obtaining this permit by misrepresentation or failure to disclose fully all relevant facts;

   c. A change in any condition that requires either a temporary or permanent reduction or elimination of a permitted discharge; or

   d. Information that the permitted discharge of any pollutant poses a threat to human health, welfare, or the environment.

(Sections 120-02-11 and 120-08-01 of State Regulations)

12. The permittee shall allow authorized local, state and federal representatives, upon the presentation of credentials:

    a. to enter upon the permittee's premises on which the facility is located or in which any records are required to be kept under the terms and conditions of this permit;

    b. to have access to and copy at reasonable times any records required to be kept under the terms and conditions of this permit or the State Air Pollution Control Board Regulations;

    c. to inspect at reasonable times any facility, equipment, or process subject to the terms and conditions of this permit or the State Air Pollution Control Board Regulations; and

    d. to sample or test at reasonable times.

    For purposes of this condition, the time for inspection shall be deemed reasonable during regular business hours or whenever the facility is in operation. Nothing contained herein shall make an inspection time unreasonable during an emergency.
    (Section 120-02-11 of State Regulations)

13. If, for any reason, the permitted facility or related air pollution control equipment fails or malfunctions and may cause excess emissions for more than one hour, the owner shall notify the Department (Director, Region II) within four (4) business hours of the occurrence. In addition, the owner shall provide a written statement, within seven (7) days, explaining the problem, corrective action taken, and the estimated duration of the breakdown/shut down.
    (Section 120-02-34 of State Regulations)

14. In order to minimize the duration and frequency of excess emissions due to malfunctions of process equipment or air pollution control equipment, the permittee shall:

    a. Develop a maintenance schedule and maintain records of all scheduled and non-scheduled maintenance. These records shall be maintained on site for a period of five (5) years and shall be made available to Department personnel upon request.

    b. Maintain an inventory of spare parts that are needed to

minimize durations of air pollution control equipment breakdowns.
(Section 120-02-11 of State Regulations)

15. The permittee shall have available written operating procedures for the related air pollution control equipment. Operators shall be trained in the proper operation of all such equipment and shall be familiar with the written operating procedures. These procedures shall be based on the manufacturer's recommendations, at minimum. The permittee shall maintain records of training provided including names of trainees, date of training and nature of training.
(Section 120-02-11 of State Regulations)

16. The facility shall operate in compliance with Rules 4-3 and 5-3 Toxics Pollutants Regulations. Any changes which increase the emission of any toxic pollutant or cause the emission of additional toxic pollutants may require a permit. Failure to obtain such a permit prior to construction may result in enforcement action.
(Sections 120-04-0305 and 120-05-0305 of State Regulations)

17. This permit shall become invalid if construction of the proposed replacement feather dryer is not commenced within eighteen (18) months of the date of this permit or if it is discontinued for a period of eighteen (18) months.
(Section 120-08-01 I of State Regulations)

18. In the event of any change in control of ownership of the permitted source; the permittee shall notify the succeeding owner of the existence of this permit by letter and send a copy of that letter to the Department (Director, Region II).
(Section 120-02-11 of State Regulations)

19. Annual requirements to fulfill legal obligations to maintain current stationary source emissions data will necessitate your prompt response to requests for information to include, as appropriate: process and production data; changes in control equipment, and operating schedules. Such requests for information from the Department will either be in writing or by personal contact. The availability of information submitted to the Department or the Board will be governed by applicable provisions of the Freedom of Information Act, §§ 2.1-340 through 2.1-348 of the Code of Virginia, § 10.1-1314 (addressing information provided to the Board), and § 120-02-30 of the State Air Pollution Control Board Regulations. Information provided to federal officials is subject to appropriate federal law and regulations governing confidentiality of such information.
(Section 120-02-31 of State Regulations)

20. A copy of this permit shall be maintained on the premises of the facility to which it applies.
(Section 120-02-11 of State Regulations)

SOURCE TESTING REPORT FORMAT

Cover
1. Plant name and location
2. Units tested at source (indicate Ref. No. used by source in permit or registration)
3. Tester; name, address and report date

Certification
1. Signed by team leader / certified observer (include certificate date)
* 2. Signed by reviewer

Introduction
1. Test purpose
2. Test location, type of process
3. Test dates
* 4. Pollutants tested
5. Test methods used
6. Observers' names (industry and agency)
7. Any other important background information

Summary of Results
1. Pollutant emission results / visible emissions summary
2. Input during test vs. rated capacity
3. Allowable emissions
* 4. Description of collected samples, to include audits when applicable
5. Discussion of errors, both real and apparent

* Source Operation
1. Description of process and control devices
2. Process and control equipment flow diagram
3. Process data

* Sampling and Analysis Procedures
1. Sampling port location and dimensioned cross section
2. Sampling point description
3. Sampling train description
4. Brief description of sampling procedures with discussion of deviations from standard methods
5. Brief description of analytical procedures with discussion of deviation from standard methods

Appendix
* 1. Process data and emission results example calculations
2. Raw field data
* 3. Laboratory reports
4. Raw production data
* 5. Calibration procedures and results
6. Project participants and titles
7. Related correspondence
8. Standard procedures

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* Not applicable to visible emission evaluations.

ATTACHMENT D

Emissions Calculations

<<<<<<<<>>>>>>>> **Input cells are shaded.** <<<<<<<<>>>>>>>>

NOTE: Zero (0) shows as --

Inputs INDUSTRIAL BOILER WORKSHEET **CRITERIA POLLUTANTS** 10/19/09

>>> Source Name: Valley Proteins, Inc. - Linville

>>> Registration #: 80144

>>> Boiler Capacity: 87.87 million BTU/hr (total for Units B-1, B-2, and B-3)

	THROUGHPUTS	#6 OIL		#5 OIL		#4 OIL		#2 OIL		#1 OIL		GAS		LPG		
	per hour	586	gal	0	gal	0	gal	0	gal	0	gal	0	mcf	0	gal	
>>>	per year	5,131,783	gal	0	gal	0	gal		gal		gal		mcf	0	gal	
	max. allow. / yr	5,131,783	gal	5,272,380	gal	5,345,608	gal	5,578,025	gal	5,744,533	gal	744,456	mcf	8,412,759	gal	
	Hours/yr	8760		0		0		0		0		0		0		8760 <- Total HR/YR

EMISSION FACTORS:

		#6 OIL	#5 OIL	#4 OIL	#2 OIL	#1 OIL	GAS	LPG
	FUEL:	#6 OIL	#5 OIL	#4 OIL	#2 OIL	#1 OIL	GAS	LPG
	UNITS:	(	lb/thousand gallons			)	(lb/MMft3)	(lb/thousand gallon)
	SCC#:	10200401	10200404	10200504	10200501	10200501	10200602	10201002
>>>	SULFUR	2.5 %	0.5 %	0.5 %	0.5 %	0.5 %	0 %	15 gr/100cuft
>>>	Heat Content	150,000	146,000	144,000	138,000	134,000	1,034	91,500
		BTU/gal	BTU/gal	BTU/gal	BTU/gal	BTU/gal	BTU/ft3	BTU/gal

Emission Factors	#6 OIL	#5 OIL	#4 OIL	#2 OIL	#1 OIL	GAS	LPG
TSP	9.19 S +3.22	10	7	2	2	7.6	0.6
PM10	8.03 S +2.65	8.6	6	1	1	7.6	0.6
SO2	157 S	157 S	150 S	142 S	142 S	0.6	0.1 S
CO	5	5	5	5	5	84	3.2
NOx	55	55	20	20	20	100	19
VOC	0.28	0.28	0.2	0.2	0.2	5.5	0.5

LEAD is included on HAPs worksheet

NOTE: < - revised based on small boiler data from AP-42 5th ed. Sup.B,C,D (as of 9/1/98)

EMISSIONS, UNCONTROLLED & PREDICTED: max hourly, expected annual throughput

LB/HR	#6 OIL	#5 OIL	#4 OIL	#2 OIL	#1 OIL	GAS	LPG	MAXIMUM LB/HR
TSP	15.35	0.00	0.00	0.00	0.00	0.00	0.00	15.35
PM10	13.38	0.00	0.00	0.00	0.00	0.00	0.00	13.38
SO2	229.93	0.00	0.00	0.00	0.00	0.00	0.00	229.93
CO	2.93	0.00	0.00	0.00	0.00	0.00	0.00	2.93
NOx	32.22	0.00	0.00	0.00	0.00	0.00	0.00	32.22
VOC	0.16	0.00	0.00	0.00	0.00	0.00	0.00	0.16

LEAD is included on HAPs worksheet

TN/YR	#6 OIL	#5 OIL	#4 OIL	#2 OIL	#1 OIL	GAS	LPG	TOTAL TN/YR
TSP	67.21	0.00	0.00	0.00	0.00	0.00	0.00	67.21
PM10	58.62	0.00	0.00	0.00	0.00	0.00	0.00	58.62
SO2	1007.11	0.00	0.00	0.00	0.00	0.00	0.00	1007.11
CO	12.83	0.00	0.00	0.00	0.00	0.00	0.00	12.83
NOx	141.12	0.00	0.00	0.00	0.00	0.00	0.00	141.12
VOC	0.72	0.00	0.00	0.00	0.00	0.00	0.00	0.72

LEAD is included on HAPs worksheet

SUGGESTED PERMIT LIMITS: same as uncontrolled
pollutants < 0.5 tn/yr not listed

	LB/HR	TN/YR
TSP	15.35	67.21
PM10	13.38	58.62
SO2	229.93	1007.11
CO	2.93	12.83
NOx	32.22	141.12
VOC	0.2	0.72

LEAD is included on HAPs worksheet

ATTACHMENT E

Emissions Calculations for CAM Applicability

PM_{10} Emissions
Rendering Operations (CAM Analysis)
Valley Proteins, Linville, VA

Source	Source ID No.	Gases From Cookers PM_{10} lbs/yr[1]	Air Cooled & Direct Contact Condenser Efficiency %	Non-Condensible Gases PM_{10} lbs/yr[2]	Scrubber Efficiency (Venturi & Packed Tower) %	PM_{10} Emission Factor lb/ton[3]	Maximum Throughput tons/yr[4]	Controlled Emissions (PTS1) PM_{10} lbs/yr[5]
320U, 260J, Eggshell, and Feather Cookers, and Feather Dryer		158,093	50%	79,047	95%	0.0068	581,226	3,952
		tons/yr		tons/yr				tons/yr
		79.05		39.52				**1.98**

[1] Estimated PM_{10} emissions contained in cooker exhaust. The PM_{10} value represents uncontrolled emissions and was derived from the Winchester, VA scrubber outlet test data and known control efficiencies for venturi/packed tower scrubbers and condenser.

[2] Estimated PM_{10} emissions contained in non-condensible gases exiting the condensers. The PM_{10} value was derived from the Winchester, VA scrubber outlet test data and known control efficiencies for scrubbers. Valley Proteins believes that the non-condensible gases from the condensers represent the uncontrolled emissions, since the condensers are an integral part of the cooker system. The cooker system requires these devices to capture and remove solids to recover as finish product, instead of losing product to the atmosphere.

[3] PM_{10} emission factor is derived from the December 2 and 3, 2003 stack test data (tested @ outlet to 3,000 cfm and 6,000 cfm packed tower scrubbers) conducted at the Winchester, VA plant. The outlet gases tested are non-condensible and high intensity gases from the cookers and process equipment.

[4] The maximum throughput is derived from the maximum hourly rate: 22.5 tph * 8760 hpy for 320U, 18.1 tph * 8760 hpy for 260J, 10 tph * 8760 hpy for Dryer, 3.5 tph * 8760 hpy * 2 for the Eggshell Cookers, and 1.75 tph * 8760 hpy * 5 for the Feather Cookers.

[5] For this analysis it was assumed that PM is equal to PM_{10} and that the venturi and packed tower scrubbers have a combined efficiency of 95%.

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Valley Proteins, Inc.
Winchester, VA Facility
PM Test Data
Winchester, VA Test Data (December 2 and 3, 2003)

Cooker Equipment Operating	Test Run #	Production (lbs/hr)	3,000 cfm Packed Tower Scrubber (PTS1) Outlet Results (lbs/hr)	Scrubber Outlet PM Emission Factor (lbs/ton)	Production (lbs/hr)	6,000 cfm Packed Tower Scrubber (PTS2) Outlet Results (lbs/hr)	Scrubber Outlet PM Emission Factor (lbs/ton)
Winchester, VA (Stack Test Results for Scrubber Outlet)							
320U Cooker, 2 Batch Feather Cookers	1	68,878	0.288	0.0084	70,485	0.075	0.0021
320U Cooker, 2 Batch Feather Cookers	2	70,485	0.103	0.0029	70,485	0.037	0.0010
320U Cooker, 2 Batch Feather Cookers	3	70,485	0.184	0.0052	70,485	0.028	0.0008
Average =		69,949	0.191	0.0055	70,485	0.046	0.0013

Cooker Equipment Operating	Test Run #	Total Scrubber Outlet Results (lbs/hr)	Total Scrubber Outlet PM Emission Factor (lbs/ton)
320U Cooker, 2 Batch Feather Cookers	1	0.363	0.0105
320U Cooker, 2 Batch Feather Cookers	2	0.140	0.0040
320U Cooker, 2 Batch Feather Cookers	3	0.212	0.0060
Average =		0.237	**0.0068**

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